GREEN Grid

Report

Recommendations for Ancillary Service Markets under High Penetrations of Wind Generation in New Zealand

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Disclaimer

The report has been developed for specific cases, defined in the report, and accordingly some assumptions have been made. The GREEN Grid Research team takes no responsibility for any errors or omissions in, or for the correctness of, the information contained in the report.

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For more information: https://www.canterbury.ac.nz/epecentre/research-and-innovation/green-grid/

Executive Summary

This report analyses the demand for reserves, including Ancillary Services Frequency Keeping (FK) and Instantaneous Reserves (IR), under higher penetrations of wind generation in the New Zealand power system. Recommendations are made for the development of the Ancillary Service (AS) markets to ensure security of the power system under high wind penetrations, while achieving economic efficiency.

The analysis centers around anticipating the dispatch of generation under eight scenarios of increasing wind generation. These scenarios are 500 MW to 4000 MW of extra wind generation in 500 MW steps above the current 690 MW of wind capacity. The scenarios were chosen in order to achieve 100% electricity generation from renewable resources, the maximum foreseeable installation of wind farms under current demand for electricity. Simulating the dispatch is modelled on historical data from 2013 to 2015 inclusive, which has sufficient data to accurately model the impacts, and a basis on which to compare the results of each scenario. The new dispatch determines the changes in the contingency risk, and the impact wind generation has on the inertia of the power system, and hence the demand for IR.

This report focuses on wind generation without consideration of other forms of renewable generation, such as Hydro, Geothermal, Solar, and Biomass. This is for the express purpose of isolating the impacts of wind generation. It is expected wind generation is going to have the greatest impact on demand for reserve as New Zealand approaches 100% renewable generation. Future demand scenarios were not considered, again for the purpose of isolating the impacts of wind generation, and the understanding that the power system is most susceptible to frequency instability under lightly loaded conditions.

Principal conclusions and recommendations are:

- It is not economic to achieve 100% renewable energy from more wind generation alone. While trying to achieve 100% renewable, wind curtailment increases greatly during periods of high wind, and thermal generation is still required for days when there is no wind and a shortage of hydro storage. Wind curtailment reduces the incentive for further expansion of wind generation.

- For 2013, minimum inertia in New Zealand reduces from 21,350 MWs in the historical scenario to 13,250 MWs for 4000 MW of extra wind capacity, 62% of the historical scenario. The years 2014 and 2015 showed a lower inertia for the historical scenario than 2013, but a higher inertia for the 4,000 MW scenarios; 14,180 and 15,700 MWs for 2014 and 2015 respectively.

- Contingency risk from thermal generators in the North Island is expected to decrease, as wind generation replaces thermal generation. This effect is greater than the impact of reducing inertia, and so the demand for Fast Instantaneous Reserves (FIR) decreases. However greater HVDC transfers, in order to obtain the benefits of spatial diversification in wind energy production, increases HVDC pole risk considerably, creating a significant demand for FIR. Overall there is greater variation in FIR demand.

- Increased HVDC transfers also increases bipole risk, which is an Extended Contingent Event (ECE), requiring a greater demand for Sustained Instantaneous Reserves, unless a greater amount of AUFLS (Extended Reserves) is obtained.

- Wind variability is expected to increase governor action by 42% with an additional 4000 MW of installed wind generation. However, this is only slightly more than when an Electric Arc Furnace was in operation in Auckland. Total demand for FK is not expected to exceed 70 MW. Therefore total variability from wind and load, under high penetrations, is comparable to historic conditions before the operation of Pole 3, needing a similar requirement in governor action and FK.

- During periods of low electricity demand, e.g. during the middle of the night, and high wind power output, there will be few hydro power turbines running to provide droop control. This condition may be unacceptable for normal frequency standards and a more active management approach may be required. A market based approach is recommended for achieving sufficient resource allocation.

- Large wind speed fluctuations will need to be considered in the procurement of Sustained Instantaneous Reserves (SIR), as the demand from thermal generator risk reduces and cause these fluctuations to become the risk setter.

- Development of the IR market should incentivise faster response over slower ones. In the situation where high HVDC transfer north causes the HVDC link to be the risk setter, the electricity market should firstly try to minimise transfer, then dispatch Interruptible Load (IL) over other reserves such as from hydro, which can then utilize its capacity for electricity generation.

- The must-run market should be reformulated to manage the curtailment of wind generation. It may be necessary to prefer hydro and other synchronous generation above wind to ensure system inertia does not get too low.

Contents

Acronyms

AGC	Automatic Generation Control
AS	Ancillary Service
ALFDD	Automatic Low Frequency Demand Disconnection
AUFLS	Automatic Under-Frequency Load Shedding
AUTC	Area under the Curve
CCGT	Combine Cycle Gas Turbine
CE	Contingency Event
EAF	Electric Arc Furnace
ECE	Extended Contingent Event
ECMWF	European Centre for Medium range Weather Forecasting
EIPC	Electricity Industry Participation Code (the Code)
ER	Extended Reserve
FFR	Fast Frequency Response
FIR	Fast Instantaneous Reserve
FK	Frequency Keeping
FKC	Frequency Keeping Control (HVDC)
FPFAPR	Fast Post-Fault Active Power Recovery
FSC	Frequency Stabilisation Control
GXP	Grid Exit Point
HVDC	High Voltage Direct Current
IL	Interruptible Load
IR	Instantaneous Reserve
MFK	Multiple Frequency Keeping
NFM	Normal Frequency Market
NMIR	National Market for Instantaneous Reserve
OCGT	Open Cycle Gas Turbine
OSS	Operating Security Standard

PI	Proportional Integral
PLSR	Partially Loaded Spinning Reserve
POR	Primary Operating Reserve
pu	per unit
RoCoF	Rate of Change of Frequency
RE-FIT	Renewable Energy Feed in Tariff
RMT	Reserve Management Tool
RR	Replacement Reserve
SIR	Sustained Instantaneous Reserve
SIR	Synchronous Inertial Response (Only used in Ireland Review)
SNSP	System Non-Synchronous Penetration
SO	System Operator
SOR	Secondary Operating Reserve
SPD	Scheduling, Pricing, and Dispatch
SR	Substitute Reserve
TASC	Technical Advisory Service Contract
TOR	Tertiary Operating Reserve
TSO	Transmission System Operator
TWDR	Tail Water Depressed Reserve
VRE	Variable Renewable Energy
WGIP	Wind Generation Investigation Project

1. Introduction

With increasing capacity of wind and solar power generation, it is important to review whether current arrangements in managing grid frequency are efficient now, and in the future. This report analyses whether current arrangements in frequency management services are satisfactory for higher wind penetrations, and recommends changes to the Ancillary Services markets that will help the further facilitation of intermittent generation. Recommendations for new market structures for frequency management are assessed by determining whether current market structures are sufficient to incentivise the most efficient resources for the expected demand.

There are four main factors when considering the impacts of intermittent generation on frequency management: reduced inertia, reduced droop, variability, and unpredictability. This report estimates likely outcomes, and considers whether these will increase the demand for frequency management services.

This report firstly provides an overview of New Zealand's current arrangements for providing frequency management in Section 2. In Section 3 the power system frequency response is examined. Section 4 briefly explains the simulation of the dispatch process. The impacts of intermittent generation on the four main factors are modelled under higher penetrations, Section 5, and the likely impacts on frequency management are discussed in Section 6. The historical availability of reserves is analysed in Section 7, and new markets and structures are recommended to increase efficiency, informed by recent changes to Irish Ancillary Services, Section 8.

2. New Zealand Frequency Management

Retaining a steady grid frequency is necessary for the efficient operation of the electricity grid. If grid frequency was allowed to significantly deviate from the nominal frequency of 50 Hz, then grid components will enter operating ranges which they cannot maintain. If this frequency is sustained, then generation will disconnect from the grid, and consequently demand will be lost, i.e. a blackout. Blackouts have a significant cost to the New Zealand economy; businesses lose means of generating revenue and residential customers are no longer able to enjoy benefits electricity provides. To minimise the risk of such events, the System Operator (SO) procures reserves to manage generation and demand imbalances that can give rise to severe frequency deviations.

The amount of reserve procured is a balance between several costs. There are three main costs: the cost of designing electrical equipment to a given frequency tolerance, the cost of lost load, and the cost of supplying reserves. It is impossible to optimally design in any explicit manner, i.e. by assigning each cost with a definable monetary value, as the problem is too complex. Instead, the Electricity Industry Participation Code (EIPC) sets standards to maintain efficiency. This section provides an overview of these standards and the means by which a balance is maintained through the energy market and reserves.

2.1. Asset Owner Requirements

To avoid generation disconnecting from the grid before reserves have had time to correct the generation and demand imbalance, generation plant has to be compatible with frequency ride through standards. For example, all generation is to remain connected to the electricity grid if the frequency is between 47.5 and 52 Hz. If frequency falls below 47.5 Hz for longer than 120 seconds, then generation can disconnect. These standards are set out in the EIPC in clause 8.19 (EIPC, 2017).

The primary influence upon these standards is the operating characteristics of Combined Cycle Gas Turbines (CCGTs), as these standards were reviewed as more CCGTs were introduced to New Zealand (Grid Security Committee (GSC), 2001). The size of New Zealand's synchronous grid is significantly smaller than European synchronous grids and other larger 50 Hz grids, however, CCGTs are designed for larger synchronous grids, as they are the principal market and have a larger demand for CCGTs units. As, a result, New Zealand has had to raise the frequency standard to be compatible with the large synchronous grids, a stricter standard to adhere to than prior to the dominance of CCGTs (GSC, 2001).

If all of New Zealand's CCGTs were removed, the frequency standard cannot necessarily return to the previous standard, as both Open Cycle Gas Turbines (OCGTs), steam turbines, and wind turbines have similar limitations, e.g. White Hill wind farm has a dispensation to disconnect at a frequency equal or above 47.5 Hz (Transpower, 2010), and there is uncertainty about the capability of other thermal plant to meet the old standard (PB Power, 2001). Therefore, this report will assume that asset standards will remain the same, and will not be widened to provide a larger range for frequency management.

2.2. The Cost of Lost Load

To avoid the economic cost to customers of unserved energy, the SO has defined Contingency Events (CEs); these are events where individual generator units unexpectedly trip, or network components are unexpectedly isolated; these definitions are further clarified in the Transpower Policy Statement (Transpower, 2017a). For a CE, the SO has to procure enough reserve so that load is not lost. The definition of CE provides a boundary to larger events, such as the loss of both HVDC poles, multiple generator unit losses, and busbar losses. For these larger events demand can be unserved.

The definition of CE is designed to ensure that the level of redundancy, including the amount of reserves procured, is kept to a practical limit. If enough reserves were procured to manage an event larger than a CE, then the cost of consistently procuring that extra reserve is considered greater than the cost of unserved energy if that event were to occur. The definition of an event greater than a CE, are all those events with an accumulative risk less than 1 in 5 years, as defined in the EIPC, 7.2 (EIPC, 2017). Transpower analyses the risk of potential events every five years in its credible event review (Transpower, 2014a), which determines the situations that are classed as CEs.

2.3. Procurement of Reserve

Reserve is defined as the capacity in which generation and demand can change real power output or consumption. Reserve is required to manage uncertainties in the generation demand balance, such as load changes or the tripping of generation. In New Zealand, reserve is only provided through generation capacity, and the capacity of load to reduce demand, however these two sources provide several services:

- Droop Response
- Instantaneous Reserves
- Frequency Keeping
- Automatic Under Frequency Load Shedding
- Over-Frequency Reserve
- Special Protection Schemes and Remedial Action Schemes

2.3.1. Droop Response

Droop response, or free governor action, is the controlled action of generator governors in response to grid frequency deviations from 50 Hz, i.e. the proportional control of generator power output in relation to frequency deviations. This response is critical for the real time balancing of generation and demand. If it were not present in the New Zealand grid, then frequency would fluctuate outside the statutory limits quickly, as other services, such as Frequency Keeping (FK), react too slowly and have limited capacity to balance normal imbalances. Droop response is insufficient to manage all imbalances, especially those caused by CCGT tripping, so Instantaneous Reserves (IR) are procured to sufficiently meet these imbalances. Consequently, IR responses are closely related to droop response.

Droop response is required of all generators synchronised to the electricity grid, as stipulated in the EIPC, Schedule 8.3, Technical Code A, Clause 5. However, in practice, it is mostly hydro generation providing a response within the normal frequency range (49.8 to 50.2 Hz), as thermal and geothermal do not respond until the frequency is outside this range, and wind turbines do not respond to any frequency deviation (Transpower, 2011). Although this appears as a breach of the Code, it is an efficient means of achieving sufficient droop response. To require more droop response from thermal, geothermal, or wind generation would introduce additional costs. For thermal generation it would reduce plant lifespan, and for geothermal and wind generation, additional cost comes from derating plant capacity and the resultant spilling of energy.

2.3.2. Frequency Keeping

FK is a centralized instruction to service providers to adjust the dispatch set point. The real power output is adjusted so that frequency is regulated to 50 Hz, and time error can be reduced to zero. Since the error between the actual frequency and 50 Hz is set to equal zero, FK integrates the error in order to remove it. By contrast droop response by itself has no ability to remove the error.

FK is an Ancillary Service (AS), i.e. a paid service, procured by the SO, from generators capable of providing the service. FK capacity is procured through the FK Market every 30 minutes, as set out in the Procurement Plan (Transpower, 2016a). The demand for FK capacity is not dynamically determined every 30 minutes, as it is for energy and Instantaneous Reserve, but is determined by the judgement of the SO. The cost of the FK service is allocated to demand customers in proportion to the amount of energy drawn from grid, as stipulated in the EIPC, 8.58. These costs have been typically about $10 million per annum, since the upgrade of the HVDC link.

2.3.3. Instantaneous Reserves

IR is an AS, procured by the SO, to ensure sufficient generation and demand is held in reserve to manage large imbalances. These imbalances are caused by CEs: especially the loss of a 400 MW CCGT unit, or the loss of a single HVDC pole. The providers of this reserve are generators that are partially loaded, hydro generators running in tail water depressed mode, and large loads that can quickly disconnect once the grid frequency has dropped below 49.2 Hz.

IR is defined by two commodities: Fast Instantaneous Reserve (FIR), and Sustained Instantaneous Reserve (SIR). FIR is procured to ensure reserve is supplied fast enough to arrest the drop in frequency after an event, while SIR ensures enough reserve is held to match the imbalance and keep the frequency within a stable range. The definition of each commodity is given in the EIPC, and the Companion Guide for Testing sets out the means of determining the capability of each generator (Transpower, 2016b).

To ensure that enough generation capacity is available for providing IR, IR is co-optimized with energy: simultaneously sharing generation capacity between the demand for energy and the demand for IR. The precise methodology of how this works is shown in the Scheduling, Pricing, and Dispatch (SPD) tool formulation (Transpower, 2016c). The demand for IR is primarily determined by the largest risk, i.e. the largest CE as determined by the largest unit synchronised to the grid at that point of time. However, particularly for FIR, the demand is influenced by the dynamic response of the grid at that point in time. This relationship is achieved by the conjunction of the SPD tool with the Reserve Management Tool (RMT) (Transpower, 2016d). Through the RMT, system inertia, among other parameters, can directly impact how much FIR is procured.

The costs of IR (about $15 million per annum) are allocated firstly to causers of events where the frequency has dropped below 49.25 Hz. This is to incentivise reliable operation of critical plant. The remaining costs are balanced between the generators and the HVDC owner, clauses 8.59, 8.64, and 8.65 of the EIPC. Rules around the trading of IR are also set in the Procurement Plan (Transpower, 2016a).

2.3.4. Over-Frequency Reserve

Over-Frequency Reserve is the capacity of generation to disconnect itself if the frequency rises too high: response is triggered for frequencies at 53 and 54 Hz in the South Island. This service is necessary for managing situations where the HVDC link trips during times of high power transfer, where high frequency occurs on the sending side. Over Frequency Reserve is an AS. The costs are allocated to the HVDC owner, as the causer of high frequencies.

2.3.5. Automatic Under-Frequency Load Shedding

Automatic Under-Frequency Load Shedding (AUFLS) is the emergency disconnection of load for events that are larger than a CE which result in the system frequency falling too quickly for generation to react. AUFLS is not an AS, as the service is not procured but is mandatory. The service is set up by placing relays on distribution feeders, this service allows for the sacrificial loss of some load, in order to retain the majority.

AUFLS is changing to the new Extended Reserve (ER) arrangements. These arrangements seek to improve the technical capabilities by changing the number of blocks and trigger frequencies for better power system stability after large contingencies. Secondly, the process of deciding which feeders should form these blocks is formalized: (1) to ensure sufficient load is present in each block, and (2) to find the optimal feeders with the lowest unserved energy costs.

2.3.6. Special Protection Schemes and Remedial Action Schemes

These are means by which the SO maintains power system stability under special situations. For example, when Tiwai Aluminum Smelter changes a pot line, Manapouri will match the change in power output in order to maintain a balance in the South Island. This relationship is not defined formally in the code, but an arrangement exists between the parties.

3. New Zealand Power System

Before the impacts of wind generation on the New Zealand power system are discussed, the characteristics of the New Zealand power system are described. This provides a physical interpretation of how reserves fit into the control of the New Zealand electricity grid. The characteristics of each power system are unique, and are heavy influenced by the size and the type of generation connected to it; New Zealand is no exception. The New Zealand power system is characterized by two small synchronous networks linked by an HVDC transmission line, where a significant portion of generation is produced by hydropower.

3.1. Rate of Change of Frequency

The control of grid frequency is dependent on three factors: the natural response of the grid, the uncontrolled changes in real power from and into the network, and the ability to control real power flows. These three factors are expressed in the swing equation:

$$2H\frac{df}{dt} = \Delta P_m - \Delta P_e \tag{3.1}$$

where H is the inertia in units of seconds, f is the grid frequency in per unit, ΔP_m is a perturbation in mechanical power imparted to the turbine by the fluid, whether that be water for a hydro turbine or steam for a steam turbine. ΔP_e is a perturbation in electrical power drawn from the system, both ΔP_m and ΔP_e are in per unit. The inertia captures the natural response of the system, as the inertia is derived from how much mass is spinning in the synchronous generators, and is not subject to control action. The electrical power captures the uncontrollability in real power flows, as loads are drawn depending on the demand for electricity, which is dependent on the decisions of people and of automated loads. The mechanical power captures the ability to control real power flows, due to generation being dispatched to equal demand, and the automatic control of turbine governors to control frequency. In summary the rate at which frequency changes is dependent on how well the governors follow unexpected demand changes and how much the spinning mass can flatten out those differences.

Formulation of frequency management in this manner is a simplification. The natural response of the power system is also dependent on the natural response of loads to grid frequency, e.g. induction generators reduce load when grid frequency drops (Kundur et al., 1994). Demand is not the only source of unanticipated changes in real power, as generators are tripped in emergencies, creating large imbalances very quickly. Also, generators are not the only means of controlling real power, as some demand has controllability as well, such as Interruptible Load (IL) in New Zealand.

Adequate frequency management involves ensuring enough capability in controlling real power flows to balance potential deviations with sufficient speed. The spinning masses of the turbines and generator rotors, a store of kinetic energy, ensures that the conservation of energy is maintained when there is a difference between electrical and mechanical power. However, if too much power is drawn from the spinning mass then grid frequency reduces, as the speed of the spinning mass decreases. How much time the system has to respond is closely related to the Rate of Change of Frequency (RoCoF). The RoCoF is calculated by rearranging Eq. 3.2 and converting from per unit values to dimensioned values:

$$RoCoF = f_b\frac{df}{dt} = f_b\frac{\Delta P_m - \Delta P_e}{2H} \tag{3.2}$$

where f_b is the nominal frequency, or base quantity of 50 Hz. To reduce the complexity of the equation, the difference in mechanical and electrical power is simplified to a single perturbation:

$$\Delta P_m - \Delta P_e = \frac{\Delta P}{S_b} \tag{3.3}$$

where S_b is the base power quantity in MW, ΔP is also in units of MW. All simulations have a base of 3,000 MW[1], unless otherwise stated. Base power is combined with inertia to give the inertia constant in MWs, i.e. $S = HS_b$. Eq. 3.2 becomes:

$$RoCoF = f_b \frac{\Delta P}{2S} \tag{3.4}$$

For example, in the New Zealand power system, large imbalances can occur when CCGT units in the North Island trip, thereby disconnecting up to 400 MW of generation from the power system; $\Delta P = -400$ MW. The inertia of the North Island power system can range anywhere between 10,000 and 20,000 MWs, setting $S = 15{,}000$ MWs (ignoring the inertia of the South Island) the RoCoF is -0.667 Hzs^{-1}. This is comparable to an actual event in the North Island where approximately 800 MW of Huntly generation tripped[2] with a sustained RoCoF close to -1 Hzs^{-1} (Transpower, 2012). The frequency in the North Island and in the South Island can fall quickly, requiring the fast response of reserves.

Comparing this RoCoF to larger grids, New Zealand's RoCoF is fast. For the United Kingdom a typical inertia value is 200,000 MWs (Ashton et al., 2015), and an imbalance as a result of tripping multiple generators is 1200 MW (National Grid, 2009). The resultant RoCoF is -0.15 Hzs^{-1}. For the Eastern Interconnection of the USA, assuming a base load of 350,000 MW (NREL, 2016), and an inertia constant of 5 s, the total inertia is 1,750,000 MWs. For a loss of 2,000 MW of generation, its RoCoF is 0.034 Hzs^{-1}. It is evident that the dynamics of the New Zealand power system are significantly different to those of larger power systems, consequently requiring a faster response in reserves.

3.2. Generator Response Time

For a large imbalance, generation has to respond in sufficient time before the frequency falls below the minimum operating frequency to avoid cascade failure. This section demonstrates the importance of adequate generator response time by modeling the system frequency for a generation trip. Then the sensitivity of the minimum event frequency to system parameters is analysed. This is followed by a presentation of the relationship between inertia, event size, and required response time.

The power system model is represented in Figure 3.1. The model consists of an inertia and a natural response by loads, which is defined by the load damping constant, D, which is further discussed in Section 3.5.3. For a large system event, such as tripping 400 MW of a CCGT unit, demand is assumed to remain unchanged, i.e. $\Delta P_E = 0$. Any dynamic changes in demand are captured in the load damping constant. The mechanical power, ΔP_M, suddenly drops as generation is lost, as shown in Figure 3.2. After the other generators have had time to respond, τ_d, they start to ramp up generation until the lost generation has been replaced; the time where all generation is replaced is τ_r, the response time.

[1] A power base of 3,000 MW was chosen due to the average demand of the North Island. This value has no material consequence, rather is an appropriate value to provide perspective in analysing the power system.
[2] This event was a particular large event where multiple Huntly generation units were isolated from the grid in December 2011, resulting in a very fast drop in frequency below 47.8 Hz, tripping the first AUFLS block.

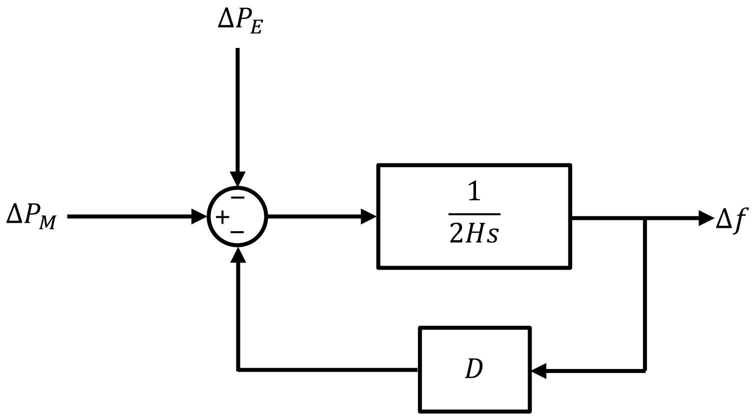

Figure 3.1: Block Diagram of the power system's natural response to generation and demand imbalances.

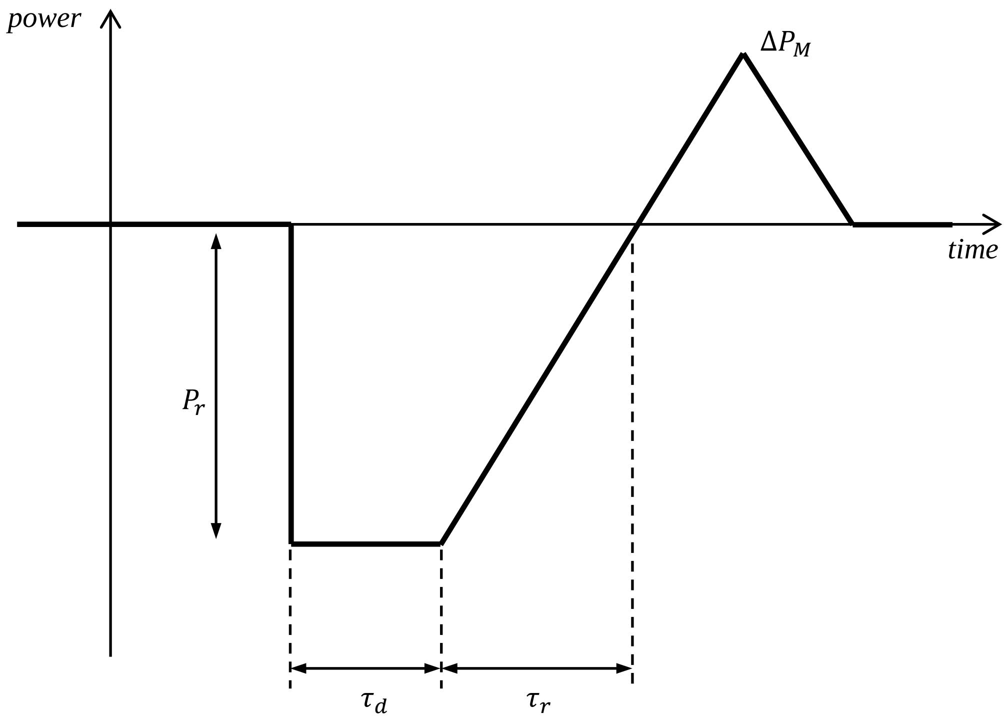

Figure 3.2: Combined turbine mechanical power during a loss of generation. This figure also defines the parameters P_r, the lost generation (pu); τ_d, the delay time to respond (s); and τ_r, the time to respond in equal magnitude to the lost generation.

The response of system frequency is presented in Figure 3.3, the minimum frequency for this event was 48.82 Hz. To understand how the power system parameters and the event size affect the minimum frequency, the equation for the minimum frequency is derived analytically (the derivation is in Appendix A):

$$f_{min} = f_b - \frac{P_r \tau_c f_b}{2H\tau_r}\left(\tau_c \ln\left(\frac{\tau_c}{\tau_r + \tau_c e^{\tau_d/\tau_c}}\right) + \tau_d + \tau_r\right) \quad (3.5)$$

where τ_c is the natural time constant of the power system:

$$\tau_c = \frac{2H}{D} \tag{3.6}$$

The sensitivity of the minimum event frequency to event parameters is calculated by taking the partial derivative and choosing parameters that reflect the normal state of the electricity grid. These parameters are stated in Figure 3.3. The results of this sensitivity analysis show that the delay time is 2.6 times more critical than the response time. Therefore, improving the time delay is 2.6 times more effective than improving the response time.

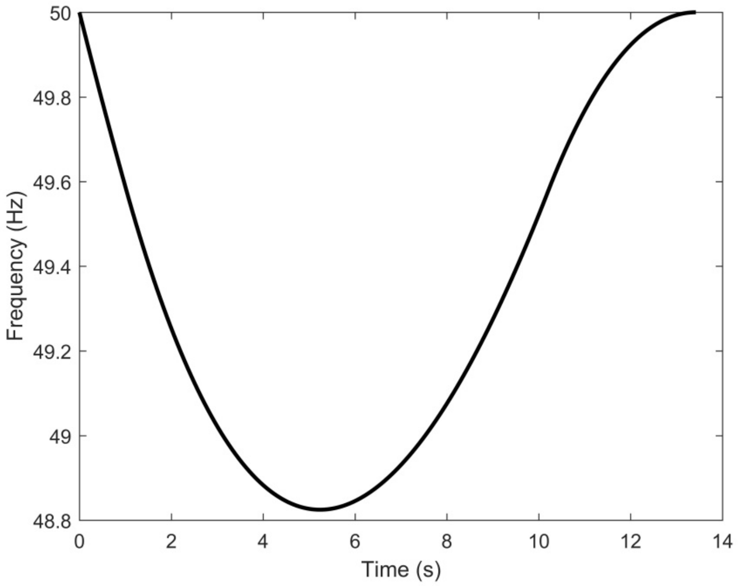

Figure 3.3: Modelled frequency transient, for a 400 MW loss of generation. $S = 23{,}000$ MWs ($H = 7.67$ s), $D = 5/3$ pu, $\tau_d = 1$ s, and $\tau_r = 6$ s.

The response time is closely related to the quantity of Fast Instantaneous Reserve (FIR) procured; in this model the response time, τ_r, defines the slope of increasing generation, whereas in the power system the quantity of procured FIR has a significant determination on the slope. Therefore, if the response time needs to be faster, i.e. τ_r needs to be smaller, this implies a greater demand for FIR. In New Zealand, the time delay, τ_d, is determined by the performance of the control systems and the physical limitations of the plant, which is difficult to adjust. The time delay, τ_d, and the RoCoF are critical factors: for fast RoCoF or long τ_d there is no response time that can prevent the frequency reaching 48 Hz, and both have a strong effect on the required reserves. To avoid these situations, the size of the CE and the amount of inertia present are required to be within limits to minimise RoCoF, otherwise there is no means of avoiding load shedding. The relationship between inertia and the required FIR reserve has been analysed by Transpower (Pelletier, Phethean & Nutt, 2012), but the relationship is more formally defined as follows.

Table 3.1: Sensitivity analysis of the minimum frequency to changes in the system and event parameters.

Quantity	Derivative	Units	Sensitivity	Example
Lost Generation	$\frac{\partial f_{min}}{\partial P_r}\frac{1}{S_b}$	Hz / MW	-2.94×10^{-3}	For a 10 MW increase in event size the minimum frequency will decrease by 0.029 Hz
Response Time	$\frac{\partial f_{min}}{\partial \tau_r}$	Hz / s	-0.0935	For a 1 s increase in response time the minimum frequency will decrease by 0.094 Hz
Delay Time	$\frac{\partial f_{min}}{\partial \tau_d}$	Hz / s	-0.246	For a 1 s increase in delay time the minimum frequency will decrease by 0.25 Hz
Inertia	$\frac{\partial f_{min}}{\partial H}\frac{1}{S_b}$	Hz / MWs	3.51×10^{-5}	For 1000 MWs increase in inertia minimum frequency will increase by 0.035 Hz
Load Damping	$\frac{\partial f_{min}}{\partial D}$	Hz / pu	0.221	For an increase of load damping constant of 0.5 pu the minimum frequency will increase by 0.11 Hz.

To analyse the point where the required response time rapidly decreases, f_{min} is set to 48 Hz, and Eq. 3.7 is rearranged:

$$\frac{f_{min} - f_b}{RoCoF} = \frac{\tau_c}{\tau_r}\left(\tau_c \ln\left(\frac{\tau_c}{\tau_r + \tau_c e^{\tau_d/\tau_c}}\right) + \tau_d + \tau_r\right) \tag{3.8}$$

The uncontrolled time to reach f_{min}, τ_m, is defined by Eq. 3.9. This equation determines the time required for the system to reach f_{min} without any response, either from the natural response of loads, or the controlled response from generators. The definition of τ_m is pictured in Figure 3.4. For the example of Figure 3.3, τ_m is 4.6 seconds.

$$\tau_m = \frac{f_{min} - f_b}{RoCoF} \tag{3.9}$$

Substituting Eq. 3.9 into Eq. 3.8:

$$\tau_m = \frac{\tau_c}{\tau_r}\left(\tau_c \ln\left(\frac{\tau_c}{\tau_r + \tau_c e^{\tau_d/\tau_c}}\right) + \tau_d + \tau_r\right) \tag{3.10}$$

Eq. 3.10 supplies a means of analyzing how the response time, τ_r, would need to be adjusted in order to maintain a minimum frequency of 48 Hz for changes in τ_m, and τ_d. τ_m is inversely proportional to the size of the event and proportional to the amount of inertia, therefore a larger τ_m is preferred. The delay time determines when generation can start to respond; therefore a small time delay is preferred. The relationship between τ_r and τ_m is presented in Figure 3.5, where τ_c is 9.2 s, and τ_d is 1 s. The response time must be small when τ_m nears τ_d, therefore τ_m has a minimum value so as to have a practical response time for generation.

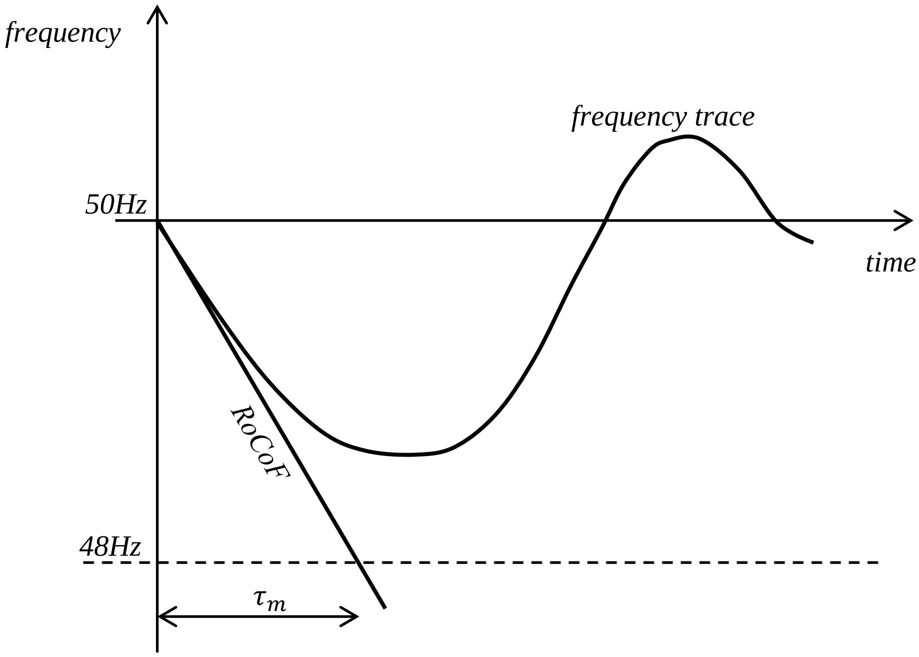

Figure 3.4: Definition of τ_m in relation to a CE.

In comparison to the United Kingdom, and the Eastern Interconnection of the United States, τ_m is small in New Zealand. For New Zealand, τ_m is 4.6 s for example. Taking the same comparable events from Section 3.1, for the United Kingdom, τ_m is 13.3 s. For the Eastern Interconnection, τ_m is 58.8 s.

To consider the impacts of the time delay, τ_d, on the required response time, Eq. 3.10 is rearranged for τ_d:

$$\tau_d = \frac{\tau_m \tau_r}{\tau_c} - \tau_r - \tau_c \ln\left(\frac{\tau_c}{\tau_r}\left(1 - e^{\frac{\tau_m \tau_r}{\tau_c^2} - \frac{\tau_r}{\tau_c}}\right)\right) \qquad (3.11)$$

The relationship between τ_d and τ_r is plotted in Figure 3.6. Provided that τ_m is sufficiently large, the time delay is not absolutely critical. However, in practice τ_m can be quite small, i.e. 2 s, therefore it is absolutely critical that the time delay be as small as possible.

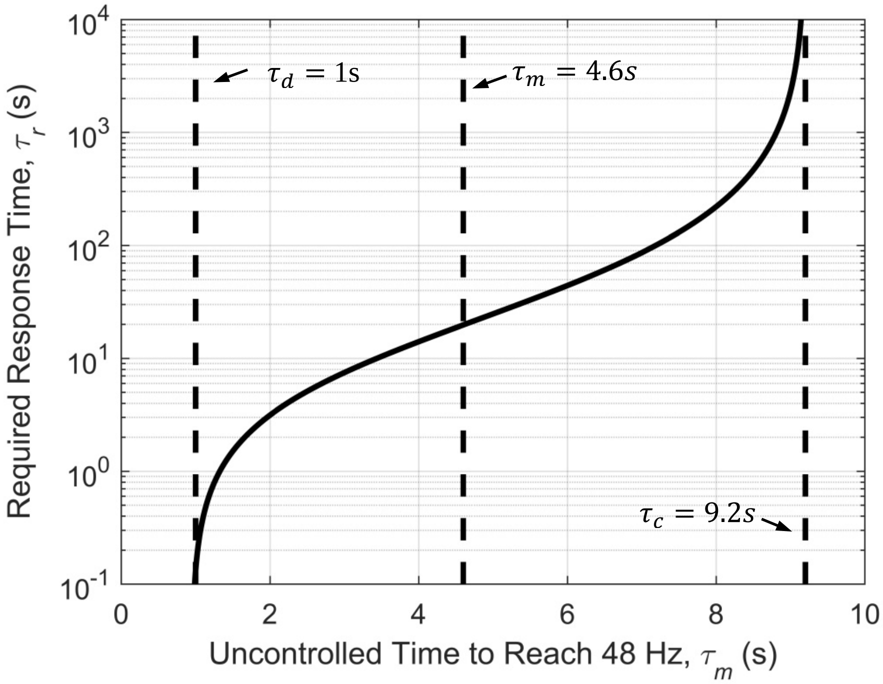

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Figure 3.5: The required response time, τ_r, to ensure the frequency does not fall below 48 Hz, for a given uncontrolled time for the frequency to reach 48 Hz, τ_m. The response time of most hydro generation is between 4 and 6 seconds. To avoid situations where hydro generation is unable to respond quickly enough; τ_m should be above 2 s, or a RoCoF of -1 Hz/s. These events do occur and require the emergency shedding of load, which has a smaller time delay.

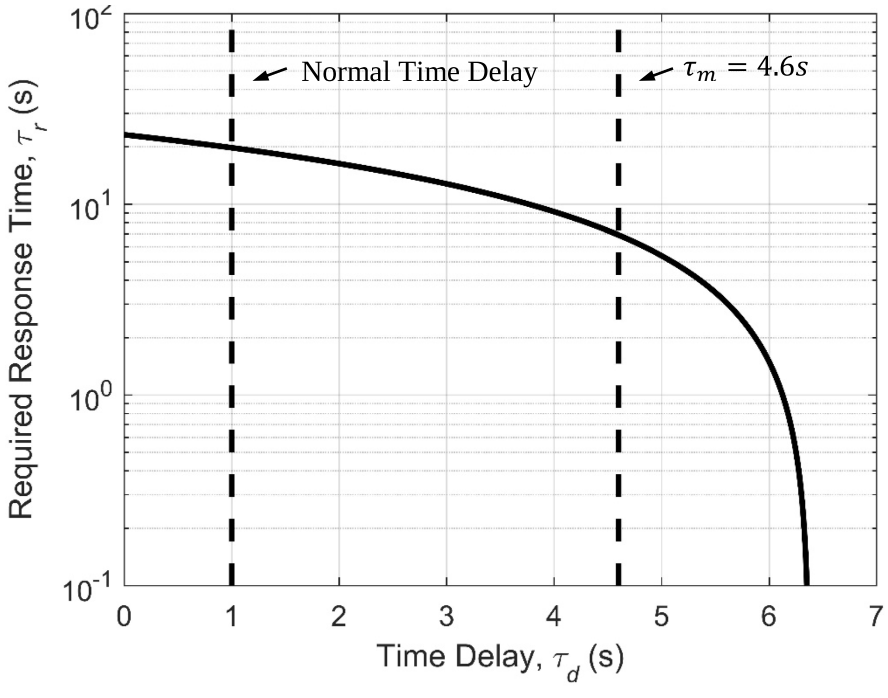

Figure 3.6: For an event where $\tau_m = 4.6s$, the required response time, τ_r, to ensure the frequency does not drop below 48 Hz, for a given time delay, τ_d.

3.3. Normal Frequency Management

The previous section highlighted how large imbalances as a result of large generators tripping from the grid are managed. This section discusses how normal variations are managed, i.e. for variations in which the time to reach 48 Hz for an imbalance is greater than the natural response time of the power system, $\tau_m > \tau_c$. This is done by finding the frequency response of the power system. The first model to be analysed is that of Figure 3.1, the purpose of this model is to determine how the natural response of the system balances out variations. The input to this model is both the mechanical and electrical power:

$$P = \Delta P_m - \Delta P_e \tag{3.12}$$

Therefore, the s-domain transfer function of the power system is:

$$G_1(s) = \frac{F(s)}{P(s)} = \frac{1}{2Hs + D} \tag{3.13}$$

The parameters of the model are $H = 23/3$ seconds and $D = 5/3$ to match the previous example, and to represent the conditions of the New Zealand grid in general according to Table 3.2. The scaling uses the same per unit quantities as the previous section. The frequency response of the system is shown in Figure 3.7. The cutoff frequency of the natural response is 0.028 Hz, i.e. oscillations with a period shorter than 35 seconds will be limited by the inertia of the system, whereas oscillations of a longer duration are limited by the natural response of the loads. Also, any demand oscillations shorter than 10 seconds are imperceptible, as the inertia of the system attenuates these variations significantly.

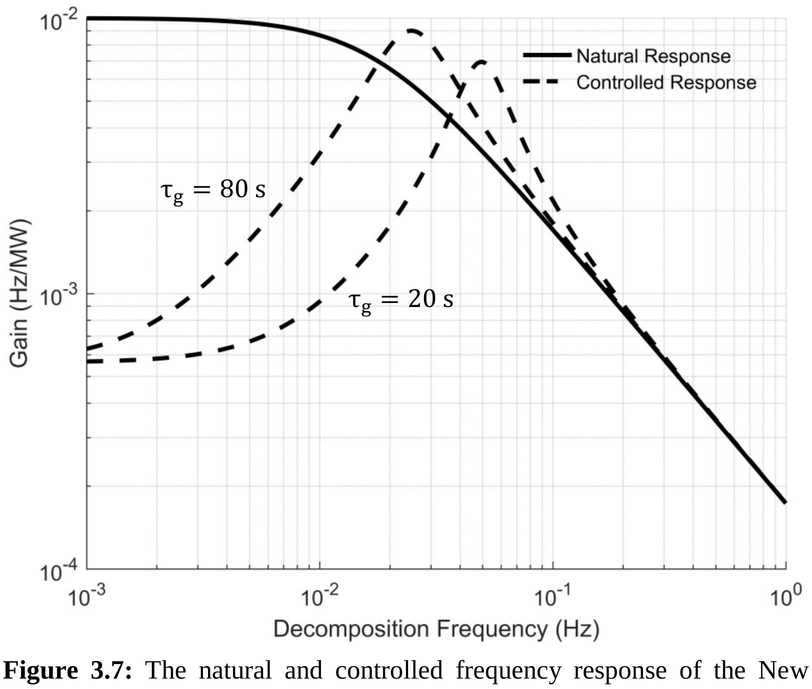

Figure 3.7: The natural and controlled frequency response of the New Zealand power system. The controlled response is shown for the estimated governor response time, $\tau_g = 80\ s$, and the potential response for a faster governor, $\tau_g = 20\ s$. For both controlled responses, the droop, R, is 28 pu.

The controlled response is the movement of turbine governors to regulate real power flows, so as to keep the frequency constant. The controlled response is modelled as a first order model of the governor system, Figure 3.8.

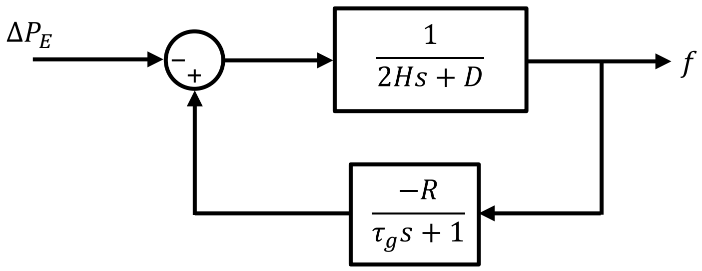

Figure 3.8: Control block diagram of the natural response of the system, and the governor action to control grid frequency.

The parameter R is the combined droop of the New Zealand power system, and τ_g is the estimated response time for the average New Zealand hydro governors. Droop is 28 pu on average for the whole of New Zealand, and the governor time constant is 80 s. The transfer function of this system is:

$$G_2(s) = \frac{F(s)}{\Delta P_E(s)} = \frac{(\tau_g s + 1)}{(2Hs + D)(\tau_g s + 1) + R} \tag{3.14}$$

The controlled response reduces the steady state gain from the natural response of $1/D$ to $1/(D + R)$. Since $R \gg D$ this reduction is large, from 0.01 Hz/MW to 0.00056 Hz/MW at steady state. This reduction of steady state gain is the intention of the controller; however, the limited response time of the governors means it cannot reduce all oscillations, which is seen by the peak in the controlled frequency response at 0.025 Hz, or oscillations of a 40 second period. The formula for the oscillation frequency with the maximum gain is determined to analyse the impacts of system parameters:

$$f_{max} = \frac{1}{2\pi\tau_g}\sqrt{-1 + \frac{1}{2H}\sqrt{\tau_g R(4H + 2D + \tau_g R)}} \tag{3.15}$$

As $\tau_g R \gg 4H + 2D$, Eq. 3.15 can be approximated by:

$$f_{max} = \frac{1}{2\pi\sqrt{2H}}\sqrt{\frac{R}{\tau_g}} \tag{3.16}$$

Increasing the droop, R, and decreasing the generator response time increases the peak oscillation frequency, and therefore shifts the peak beyond which the inertia attenuates the imbalance. This is seen in Figure 3.7, where the response time of the generator is decreased from 80 s to 20 s.

The spectrum of the grid frequency is shown in Figure 3.9 and Figure 3.10, for the North Island and the South Island for the two years 2014 and 2015. The South Island frequency variation is less than that of the North Island, which is seen by the relative strength of the signals at low frequencies, and is confirmed in Figure 3.11. This difference is due to the greater quantity of droop in the South Island and the reduced variability in demand and wind generation in the South Island.

In the spectrum range from 0.01 to 0.1 Hz (oscillations from 100 to 10 seconds) of Figure 3.8, the North Island and the South Island amplitudes are very similar. This is because of the Frequency Stabilisation Control (FSC), which existed on Pole 2 prior to the implementation of Frequency Keeping Control (FKC) (Teeuwsen, Love, and Sherry, 2013). FSC reduces the fast frequency oscillations in both islands by combining the inertias of both islands, and by combining the real power variations. A control diagram of FSC and FKC are provided in (Teeuwsen et al., 2013). The impact of FKC is seen Figure 3.10, where the frequencies of both islands are very similar.

In the same spectrum range, from 0.01 to 0.1 Hz, there is a slight peak in the magnitude, especially for the North Island in 2014. This peak corresponds with the anticipated peak caused by the finite response time of generator governors.

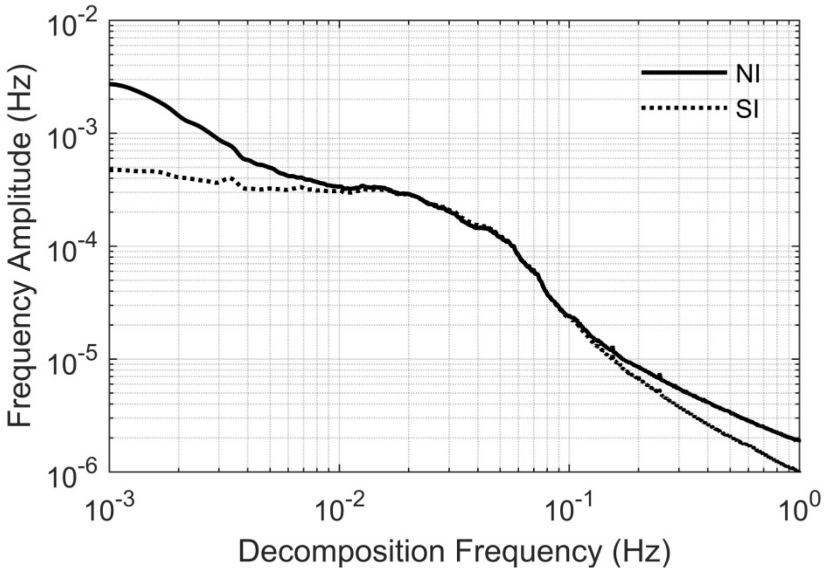

Figure 3.9: Spectrum of the North Island (NI) and South Island (SI) grid frequencies for 2014. Note units on the y-axis are not strictly correct, as this is a spectral density plot and so the units should be Hz/Hz. However, the Hz on the numerator refers to grid frequency, whereas the Hz on the denominator refers to the decomposition frequency of the grid frequency signal. This is also the case for Figure 3.10.

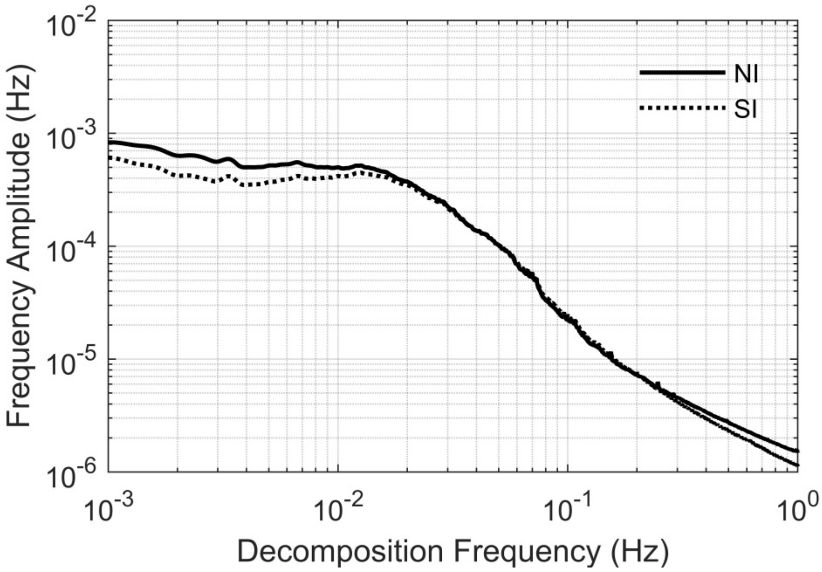

Figure 3.10: Spectrum of the North Island (NI) and South Island (SI) grid frequencies for 2015.

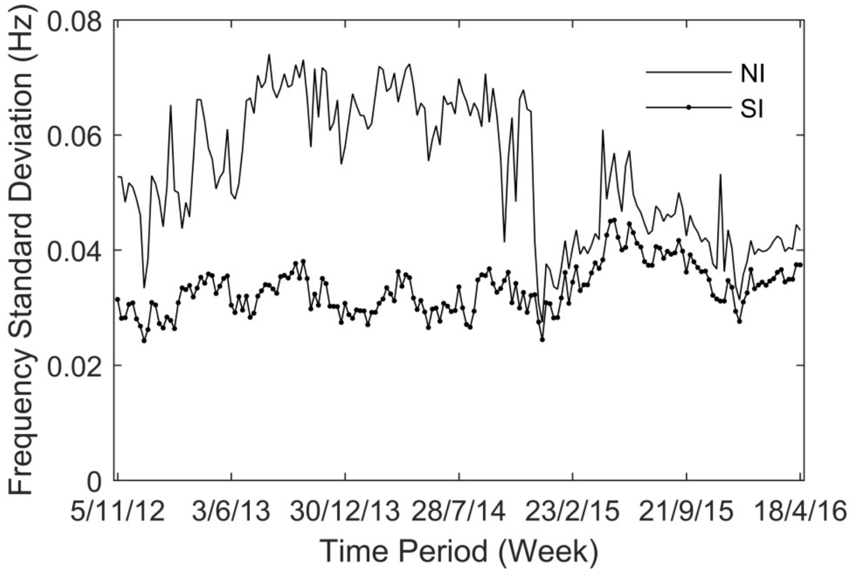

Figure 3.11: Weekly time series of frequency standard deviation for the North Island and the South Island.

The variation in grid frequency can be characterised by its standard deviation, where in Figure 3.11 it is shown on a weekly basis. The standard deviation of the North Island power system has historically ranged from 0.03 to 0.075 Hz, whereas for the South Island the standard deviation has ranged from 0.02 to 0.04 Hz. This is comparable to the standard deviations of Western Australia and Iceland; both isolated grids Western Australia is similar in size to the North Island power system, and has a frequency standard deviation ranging from 0.013 to 0.02 Hz for a period from 2013 to 2015 (Western Power, 2015), while Iceland is similar in size to the South Island power system, and has a frequency deviation of 0.046 Hz for 2015 (Landsnet, 2015).

The frequency standard deviation provides a means of analyzing the performance of the grid as changes in frequency management occur. These changes are seen in Figure 3.11, especially for the North Island. Firstly, the frequency standard deviation worsened from July 2013 as Frequency Keeping (FK) transitioned from a faster single frequency keeper to the slower Multiple Frequency Keeping (MFK) system; secondly the frequency standard deviation improved at the start of 2015 as FKC was implemented between the two islands. The consequence of FKC operation is that the North Island and South Island frequency become similar, as FKC tries to equalize the two grid frequencies. South Island also transitioned to MFK; however, the transition during August 2014 is not noticeable.

Frequency standard deviation also has a daily trend. This effect is analysed by considering the frequency standard deviation by hour of the day, Figure 3.12. During the early hours of the morning the frequency standard deviation is high, as demand is low. Once demand starts to increase, the frequency standard deviation improves. This is a consequence of greater amount of inertia and droop during periods of higher demand, with a relatively minor increase in demand variability.

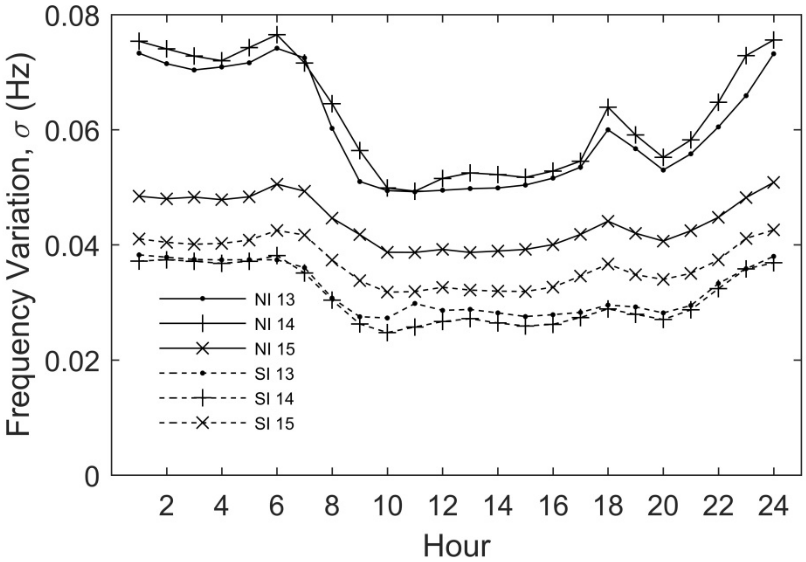

Figure 3.12: Frequency standard deviation for each hour of the day, which is averaged over a year. NI, North Island; SI, South Island. 13 refers to 2013, and similarly for 14 (2014) and 15 (2015).

3.4. Frequency Keeping

Frequency Keeping (FK) is an Ancillary Service (AS) procured by the System Operator (SO). FK works by the SO monitoring the grid frequency and regularly sending instructions to generators to adjust dispatch. The instruction is created through a Proportional-Integral (PI) controller, Figure 3.13. The integral component is designed to reduce the steady state frequency error and return the frequency to 50 Hz. FK includes other functions, such as correcting time error and indirectly correcting error in the dispatch.

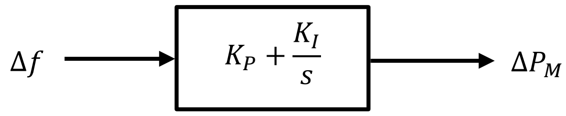

Figure 3.13: Control block diagram of the PI controller used for Frequency Keeping, K_P is the proportional gain, and K_I is the integral gain.

The speed at which FK operates is dependent on three factors: the parameters of the PI controller, the maximum ramp limit, and the response time of the service providers. Firstly, the maximum ramp limit is set to 0.4 MW per min per MW of FK reserve, clause B5.2 (Transpower, 2016a). For the current requirement of 30 MW of FK reserve, the maximum ramp limit is set to 12 MW/min.

The response time of the service providers of FK has the most impact on the ability of FK to improve frequency deviations. Since the main service providers are hydropower units in both the North and South Islands, their generator response time, τ_g, is somewhere around 80 seconds. Therefore, FK has no ability to reduce the peak in the controlled frequency response of Figure 3.7, and can only influence fluctuations with a period longer than one or two minutes. The response time of the service providers also sets a practical limit on the PI parameters, because if the parameters are set high, then the controller will respond to fluctuations it cannot improve.

The impact that FK has on frequency quality is limited by the amount of FK reserves dispatched, and how much droop is currently connected to the grid. Droop is important because it determines the steady state frequency deviation for a deviation from dispatch. From the previous section the steady state gain of the response is 0.00056 Hz/MW. Hence for a FK reserve capacity of 30 MW, FK can only improve the frequency by 0.017 Hz, i.e. if frequency is steady at 50.05 Hz, then FK can improve frequency to 50.033, but no more. This improvement of 0.017 cannot be maintained consistently, due to the finite response time of the controller.

FK also has a purpose of reducing time error by adjusting the target frequency in the controller. Time error adjustments are required to ensure that clocks synchronised to the grid frequency do not accumulate error, therefore the time average of the frequency has to be 50 Hz. For example, if the average grid frequency is 49.5 Hz over a particular period, then the system operator sets the target frequency to 50.5 Hz for a later period. In the future, the necessity for time error correction is a matter of debate in New Zealand and overseas, as most synchronous clocks have become obsolete (Transpower, 2011).

FK is also not the only method of correcting time error. Time error can be adjusted by biasing the dispatch, which purposefully creates a deviation between generation and demand for droop response to correct, which by necessity produces a bias in the frequency. This method works well when FK is not in operation, and has been trialed on occasion (Transpower, 2015) (ECNZ, 1998). This second method is to adjust the target frequency of each governor synchronized to the grid, which is the method used in the United Kingdom, as required in the Grid Code clauses CC.6.3.7 (d), BC 2.10.2 (e), BC 3.4.2, and BC 3.4.3 (National Grid, 2017).

3.5. System Parameters

In Sections 3.1 to 3.3 the characteristics of the New Zealand power system are defined in terms of its inertia, H; load damping constant, D; droop, R; and the generator response time, τ_g. This section explains the calculation of these quantities for the New Zealand power system, and the distribution of these quantities for 2014.

3.5.1. Inertia

Inertia is determined by how many generator rotors are synchronised to the electricity grid. If a unit is synchronized to the grid, the individual inertia of the generator becomes part of the combined inertia. The inertia of an individual unit is set by the per unit quantity inertia, H_i in seconds, where i is an index of individual units, and the power base, S_i in MVA. The power base is unique to each station, and is usually the maximum apparent power rating of the unit. The inertia, H_i, holds a particular range of values depending on the type of generation. For New Zealand generation:

- Hydro generators typically have inertia in the range of 2 to 4 s, with a few exceptions.
- CCGTs, such as Otahuhu B, Taranaki Combined Cycle, and Huntly Unit 5, have inertia between 5 and 6 s. OCGT have inertia in the range from 1 to 2 s.
- Thermal units with steam turbines, such as Huntly Rankine units and some geothermal stations have a range from between 3 to 6 s.
- Geothermal units, using a binary process, have a smaller inertia around 1 s.
- Wind generation, with the exception of Windflow turbines (Te Rere Hau), do not have inertia. Some wind farms can emulate an inertial response; however, it is limited to the more modern wind farms such as West Wind and Te Uku (Ackermann, 2012). Type I and II turbines, such as Te Apiti, also have an inertial response, but not directly comparable to a synchronous generator.

For the New Zealand power system, inertia values of each power station are published in a Transpower report (Transpower, 2014b). However, this list is not complete, with roughly 20 units omitted. For these units their inertia was estimated based on the generation technology. The total inertia is a summation of inertia from individual units:

$$HS_b = \sum_i H_i S_i \tag{3.17}$$

Eq. 3.17 is not trivial to evaluate. To create an inertia time series, it is necessary to determine when each generator is synchronized to the grid. This has been done by taking the generation profiles of individual units, which have been provided by Transpower, and checking when the units are providing energy. The results of this analysis are seen in the distribution for the North Island, South Island and the whole of New Zealand, Figure 3.14. The North Island has greater inertia than the South Island, due to the North Island having greater amount of generation.

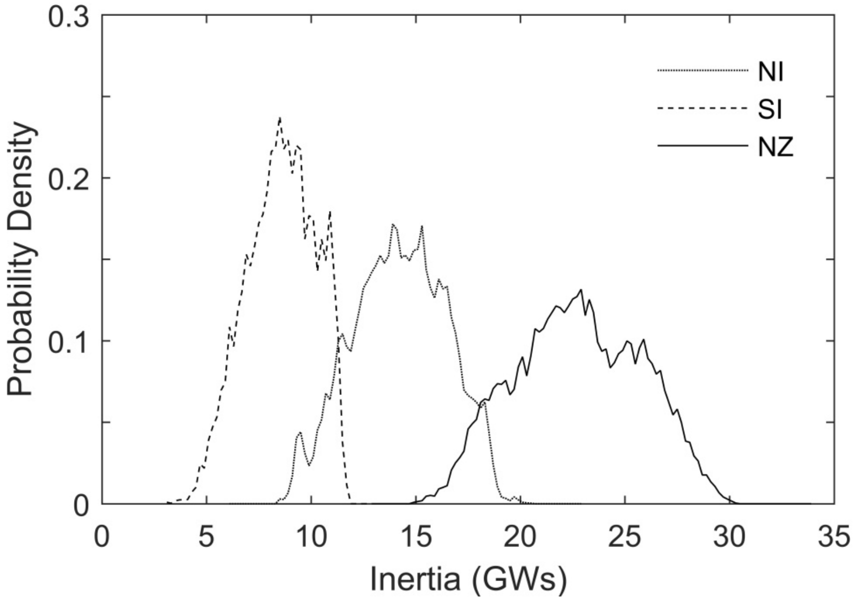

Figure 3.14: The distribution of total inertia from generation for the North Island (NI), South Island (SI), and New Zealand (NZ); for 2014.

In this estimation of inertia, several sources were not counted: the inertia from Te Rere Hau and Gebbies Pass wind farms, the inertia from synchronous condensers (Haywards and Otahuhu), and the inertia from synchronous motors. These sources were not considered because of the difficulty in determining whether these units were synchronized to the grid at anyone point in time. However, it is possible to estimate the contribution of inertia from these other sources and from demand by considering the RoCoF during actual contingent events. The details of this analysis are in Appendix G. The results indicate that for every MW of demand 1.5 MWs of inertia can be added for the North Island, and 0.75 MWs for the South Island. This is a higher estimate than Transpower uses for the Reserve Management Tool (RMT) of 0.3 MWs/MW.

New Zealand's inertia can be considered as a whole due to the Frequency Keeping Controller (FKC) installed on the HVDC link. This should not to be confused with FK, the ancillary service procured by the SO. The New Zealand total inertia is not strictly the same as the total inertia for each island, as each island has its own synchronous network. This is especially so when the HVDC is out of service.

However, the two grids act as if they are synchronised, as FKC removes the error between the frequencies of the two islands.

The total New Zealand inertia is not representative of the inertia during a contingent event either, as FKC requires a finite amount of time to respond. Therefore, during a trip in North Island generation, the initial RoCoF is only determined by the North Island inertia; only after one to three seconds does the RoCoF become dependent on all of New Zealand's inertia.

3.5.2. Droop

Droop is calculated in a similar manner to inertia, where the contribution of droop to the system is dependent on whether the unit is synchronized to the grid. The droop capabilities are defined for each generator by a percentage droop, ρ. Typical values range from 3% to 5%. The percentage droop is the required percentage reduction in frequency in order to produce the full rated response of the generator. For example, for a droop of 4%, the generator will increase output by the rated capacity of the plant if the frequency falls to 48 Hz, for other frequencies the power output is determined in a linear fashion. However, since generation plant is typically producing power, units will have limited head room, and will reach maximum capacity before the frequency reaches 48 Hz. The relationship between droop, frequency, and the resulting power output is presented in Figure 3.15.

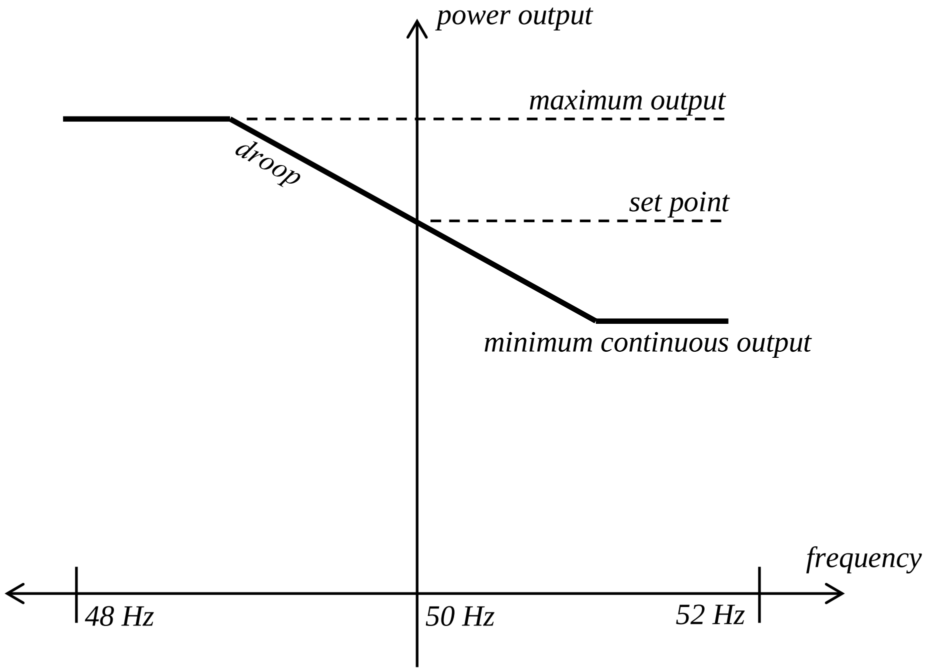

Figure 3.15: Generator real power control via a droop response.

To find the total droop for each island, the percentage droop is converted to a gain, R_i in MW/Hz:

$$R_i = \frac{S_i}{\rho_i f_b} \tag{3.18}$$

where S_i is the rated capacity of the power station, and f_b is the frequency base of 50 Hz. The total response is the summation of droop from all the connected generators:

$$R = \sum_i R_i \tag{3.19}$$

When calculating the total droop, only hydro units were considered, due to the general unresponsiveness of other generation types in New Zealand. This issue has been mentioned previously in Section 2.3.1. The droop value for each individual unit was obtained from the generator companies where possible, which are measured from unit tests; or an estimate of 4% was used for unknown units. To create a time series, total droop was calculated based on units synchronised to the grid. This is similar to the process used for calculating inertia. The distribution of droop is shown in Figure 3.16 for 2014. In contrast to inertia, the South Island has more droop than the North Island, due to the greater concentration of hydro generation.

Also in a similar manner to inertia, New Zealand droop can be considered as a whole due to the operation of the FKC. If FKC is not in operation then the total NZ droop has no meaning. The FKC, which equalizes the two grid frequencies, allows for the concerted effort of hydro generators between the two islands to manage frequency deviations.

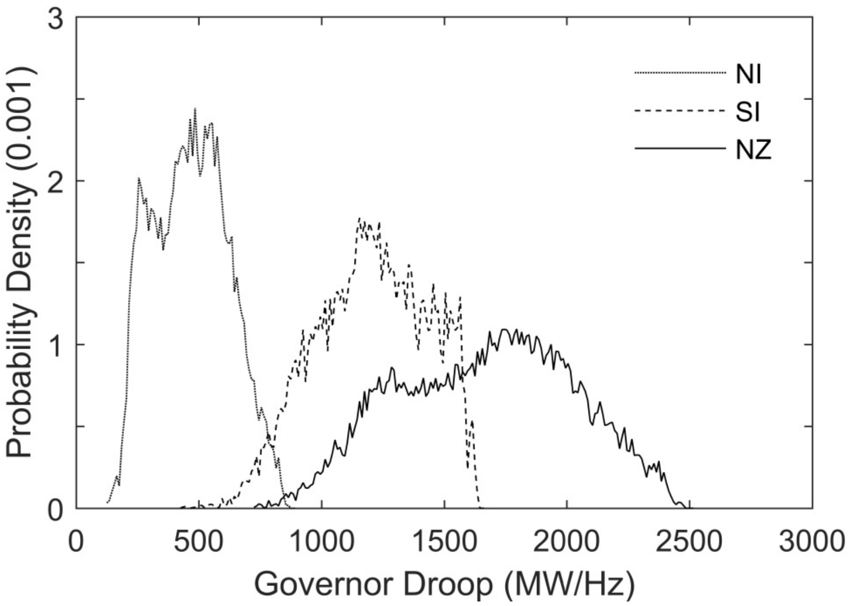

Figure 3.16: The distribution of total droop for the North Island (NI), South Island (SI), and New Zealand (NZ); for 2014.

3.5.3. Load Damping

Load damping is modelled as a single, D, and like droop measures a proportional change in power to a change in frequency. This is a simplification of the various responses of different loads types. The proportional gain is primarily attributed to motor loads. This parameter is usually somewhere between 1 and 2 pu (Kundur et al., 1994), where 2 means a 1% change in frequency will cause a 2% change in load. For example, a load of 2000 MW and $D = 1$ pu, provides a response of 40 MW/Hz. In New Zealand, the load damping is estimated to be 0.8 pu, with a power base equal to the demand at that time. The distribution of demand is presented in Figure 3.17. The statistics of inertia, droop, and load damping constant are in Table 3.2.

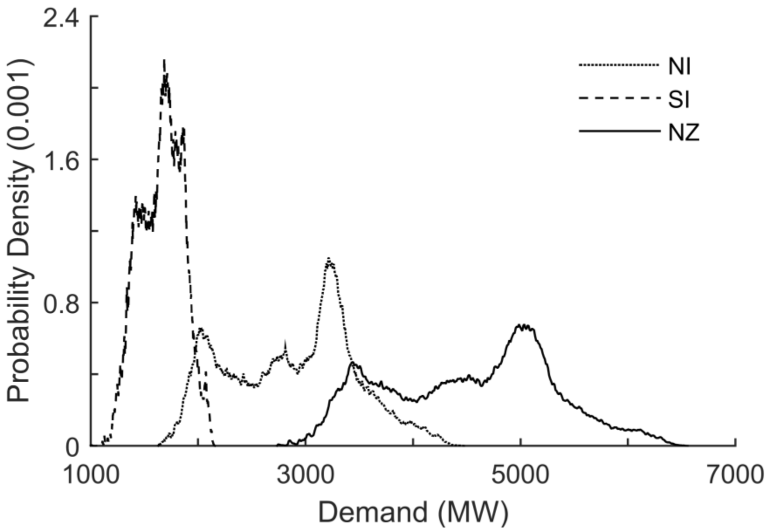

Figure 3.17: The distribution of total demand for the North Island (NI), South Island (SI), and New Zealand (NZ); for 2014.

Table 3.2: The statistics of the power system parameters for 2014. The per unit values are derived from a power base of 3,000 MW, and a frequency base of 50 Hz.

	Power System Parameters					
	Inertia		Droop		Damping	
	MWs	pu (s)	MW/Hz	pu	MW/Hz	pu
	North Island					
Mean	14,210	4.74	468	7.79	46	0.77
Standard Deviation	2,250	0.75	154	2.57	9	0.16
Minimum	8,440	2.81	128	2.13	26	0.43
Maximum	20,440	6.81	866	14.43	71	1.19
	South Island					
Mean	8,550	2.85	1,202	20.02	27	0.44
Standard Deviation	1,640	0.55	227	3.78	3	0.05
Minimum	3,040	1.01	429	7.15	16	0.26
Maximum	11,830	3.94	1,678	27.97	34	0.57
	New Zealand					
Mean	22,760	7.95	1,669	27.82	73	1.21
Standard Deviation	3,020	1.01	356	5.94	12	0.21
Minimum	14,740	4.91	672	11.20	44	0.73
Maximum	30,520	10.17	2,475	41.25	105	1.75

3.6. Dispatch Process

The dispatch process is considered because it has the primary control of power plant operation, through the generation offers placed in the electricity market. As intermittent renewable generation is an input to the dispatch process, it is necessary to analyse what impact it will have on the operation of power plant and the effect this has on the grid frequency. Therefore, the dispatch process is described in this section, and the impacts of wind generation are analysed in Section 5.4.

The dispatch process balances the main proportion of generation and demand, where the dispatch process will balance anywhere between 3,000 and 7,000 MW, reserves will balance 400 MW for several minutes, or about 30 MW consistently. Reserves only balance a small proportion of power due to the predictable nature of electricity demand and variable generation, and the limited changes that occur over a 5-minute time period – the time between when dispatch instructions are sent. The dispatch process fundamentally works with the predictable, whereas reserves work with the uncertain. Therefore, in considering the impacts of wind generation it is helpful to distinguish between what is predictable and what is uncertain in the real-time operation of the power system.

The dispatch of generation has three impacts on frequency management:

1. The next dispatch instruction may be too large for available generation, with a limited ramp rate, to respond, therefore resulting in a temporary power imbalance and corrective action.
2. The way in which generation responds to the dispatch instruction may not reflect the demand changes, i.e. a hydro generator can respond to an instruction within a couple of seconds but the changes in demand take a couple of minutes, thereby creating an imbalance.
3. An imbalance may result from incorrectly predicting and dispatching generation.

The dispatch process starts with generators placing offers, the system operator then creates schedules, which anticipates which generators will run, and the price of electricity. These schedules are progressively updated every half hour as they approach the trading period. During this time, and up to gate closure, generators can revise offers, and checks are performed by the system operator to ensure the system is secure if a contingency were to occur. Therefore, by the time dispatch instructions are sent, there has been significant planning, both by the generators and the system operator, to ensure secure operation of the grid.

The dispatch instructions are created from the same optimization formulation used to create the schedules prior to the trading period, and are used for determining the final prices. The optimization determines the least cost dispatch of generation while ensuring demand is balanced, and the constraints of the generators and power system are satisfied. Usually dispatch instructions are sent every five minutes, and occur six times per trading period; however, this can be adjusted if an emergency requires dispatching again, or there has not been a significant change in demand to warrant a new dispatch.

To balance generation and demand in the real-time dispatch, it is necessary to predict the power output of wind farms five minutes in the future, so a persistence forecast is taken, i.e. the current wind power output of the wind farm is taken as the best approximation of the power output in five minutes time.

3.6.1. Ramping Constraints

The ramping constraint, in the optimization, ensures that a generator is not instructed to change output outside of its capabilities. This is especially important for thermal and geothermal power stations. These ramp limits form a component of the offers that generators place in the market. The ramping capabilities of New Zealand generators are presented in Table 3.3, based from the offers supplied from 2013 to 2016. Geothermal has the lowest ramping capabilities; thermal has better performance, especially the Open Cycle Gas Turbine (OCGT) units at Stratford power station (referred to as Stratford Peaker in tables). These units have a combined ramp rate of 42 MW/min. Hydro generators have the best performance and practically do not have a ramp rate limit, except for a few of the smaller generators, such as Cobb, Coleridge, and the Tongariro Power Scheme.

The primary concern is the presence of not enough generation able to follow the demand profile, especially during the morning ramp up, which can be aggravated by a decrease in wind generation at the same time. The ramping profile of demand is presented in Figure 3.18. The large amount of hydro generation, and the capability of thermal generation, means that the power system is able to manage large ramping rates, certainly larger than demand, which does not ramp greater than 20 MW/min, or less than -12 MW/min for a duration greater than two hours. This is comparable to the ramp limits of the thermal units, but quite small in comparison to the hydro generators. While the New Zealand power system can manage demand ramp rates quite sufficiently, Section 5.4 predicts ramp rates for wind generation, and anticipates the consequences in Section 6.4.

Table 3.3: Ramp rate limits of New Zealand generation. Cap (Capacity) means that there is practically no ramp rate limit from the perspective of the market, as those stations can ramp their whole capacity within five minutes. Generators can set their ramp limits each half hour depending on their conditions; the range column is the historical range of values where these generators have had their maximum ramp limits, while mode is the most common limit chosen. If only one limit is ever given, that single value is expressed.

	Ramp Up Limits		Ramp Down Limits		Max Generation Limits	
	Range (MW/min)	Mode (MW/min)	Range (MW/min)	Mode (MW/min)	Max (MW)	Mode (MW)
	Geothermal					
Ohaaki	0.67-5	0.67	0.92-5	1.5	88	38
Poihipi	0.67-Cap	3	0.2-4	3	55	51
Te Mihi	1.33-13.33	2	2-13.33	2	176	166
Te Huka	0.67-3	3	1-3	3	30	24
Wairakei	0.67-6	0.67	1-3	1	180	130
Kawerau	0.6-3.5	0.6	0.6-2	0.6	107	105
Ngatamariki	1.67-2.73	1.67	1.33-2.77	1.33	86	85
Rotokawa	0.83-1.2	0.83	0.83	37	34	
Nga Awa Purua	2-4.67	2	2-4.3	2	147	134
Mokai	3-3.43	3	1-3	1	118	108
	Thermal					
Otahuhu CCGT	6.5		2.67-6.5	6.5	400	385
Stratford Peaker	41.67-42	42	6.66-42	42	210	200
TCC	10-13.17	10	3-13.17	10	400	
Huntly Unit 1	0.33-20	5	0.33-6	5	260	230
Huntly Unit 2	0.33-5	5	0.33-5	5	255	230
Huntly Unit 4	0.33-5	5	0.33-5	5	250	230
Huntly Unit 5	1-17	16.5	1-17	16.5	405	380
Huntly Unit 6	10		10		49	44
Southdown CCGT	2-4.33	2	2-4.33	2	127	42
Southdown OCGT	10		10		50	47
Kapuni	0.83		0.83		20	
McKee	5-10	6.67	5-10	6.67	100	
	Co-generation					
Glenbrook	Cap		Cap		69	52
Te Rapa	3-10	3	3	3	50	
Whareroa	1.33-1.9	1.33	1.33-1.9	1.33	34	
Onepu	0.67-1	1	0.67-1	1	60	
Kinleith	1		1		40	

	Diesel					
Whirinaki	5		5		156	
	North Island Hydro					
Rangipo	2-18	5	2-18	5	130	120
Tokaanu	17.33-26	26	17.33-26	26	240	
Kaitawa	6.4		6.4		36	34
Piripaua	8.8-12	12	8.8-12	12	44	
Tuai	12		12		63	60
Mangahao	4		4		37	29
Aratiatia	Cap		Cap		82	81
Arapuni	Cap		Cap		192	
Atiamuri	Cap		Cap		82	
Karapiro	Cap		Cap		101	64
Maraetai	Cap		Cap		318	283
Ohakuri	Cap		Cap		111	106
Whakamaru	Cap		Cap		102	100
Waipapa	Cap		Cap		59	54
Aniwhenua	2.5		2.5		25	
Patea	Cap		Cap		36	33
Matahina	0.13-Cap	0.13	0.8-Inf	Cap	80	
Wheao	Cap		Cap		26	
Kaimai	Cap		Cap		42	
	South Island Hydro					
Clyde	50		50		464	
Roxburgh	46.67-Cap	46.67	46.67-Cap	46.67	346	
Tekapo A	0.25-Cap	Cap	0.25-Cap	Cap	32	25
Tekapo B	1.4-Cap	Cap	1.4-Cap	Cap	153	143
Aviemore	Cap		Cap		216	214
Benmore	Cap		Cap		534	532
Ohau A	Cap		Cap		256	190
Ohau B	Cap		Cap		208	203
Ohau C	Cap		Cap		208	201
Waitaki	Cap		Cap		90	75
Manapouri	Cap		Cap		848	788
Argyle	Cap		Cap		12	
Highbank	Cap		Cap		28	
Waipori	Cap		Cap		101	84
Cobb	1-1.5	1.5	1.5		32	
Coleridge	1		3		39	
Kumara	0.33		0.2		7	
Paerau	Cap		Cap		12	

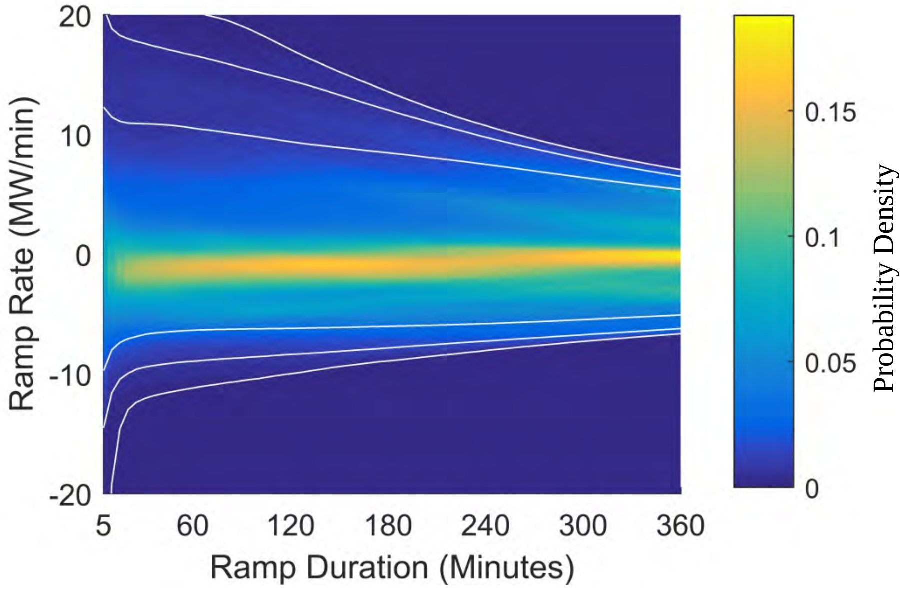

Figure 3.18: The likelihood of sustained ramping in New Zealand's demand, as the colour approaches yellow the likelihood of that event increases. The horizontal axis represents the duration of an event, e.g. for a duration of 180 minutes, the ramp rate, on the vertical axis, is the average ramp rate in demand over those 180 minutes, however the ramp rate does not have to equal the average for the whole duration. The figure is produced by determining the Probability Density Function (PDF) for each duration from a dataset of New Zealand demand (2013 to 2015 sampled every 5 minutes). By repeating the PDF for different durations an image is produced (not a two dimensional PDF). The white lines are percentile markers; starting from the bottom, the first three lines are 0.1, 1, and 5 percentiles, the second three lines are 95, 99, and 99.9 percentiles.

3.6.2. Imbalance as a result of the Dispatch

The dispatch process can adversely affect frequency quality through being a source of imbalance between generation and demand. This occurs when the dispatch instruction causes one generator to increase by a large amount and another generator to decrease by a similar amount, e.g. an instruction for the Manapouri Power Station to decrease by 105 MW and the Waitaki scheme to increase by 100 MW. If each power station follows the instruction at different time then an imbalance follows. This imbalance is not as critical as an imbalance from losing the same amount of generation through an instantaneous trip, because the imbalance increases gradually as the governor system changes the mechanical power supplied to the turbine. It also decreases gradually when the other generator responds. Furthermore, all the other generators will react through droop to keep the imbalance at a minimum.

This effect is quite noticeable when looking at the first dispatch of a trading period. In the previous dispatch the system was optimized for the previous set of offers, and so the next dispatch introduces the next optimal solution. Subsequent 5-minute dispatches only bring instructions to the marginal generator and so the change is minimal. This is seen by first considering Figure 3.19, which shows that the total change in dispatched power for the first 5-minute dispatch of the trading period is similar to the subsequent five trading periods. However, when considering the absolute change in dispatched power (total magnitude change), Figure 3.20, the first dispatch is significantly larger than subsequent five. This is consistent with the observed phenomenon that the frequency quality is noticeable worse in the first five minutes of the trading period than in the next 25 minutes of the trading period (Electricity Authority, 2015), approximately the first five minutes can be 30% worse in frequency quality than the remaining 25 minutes.

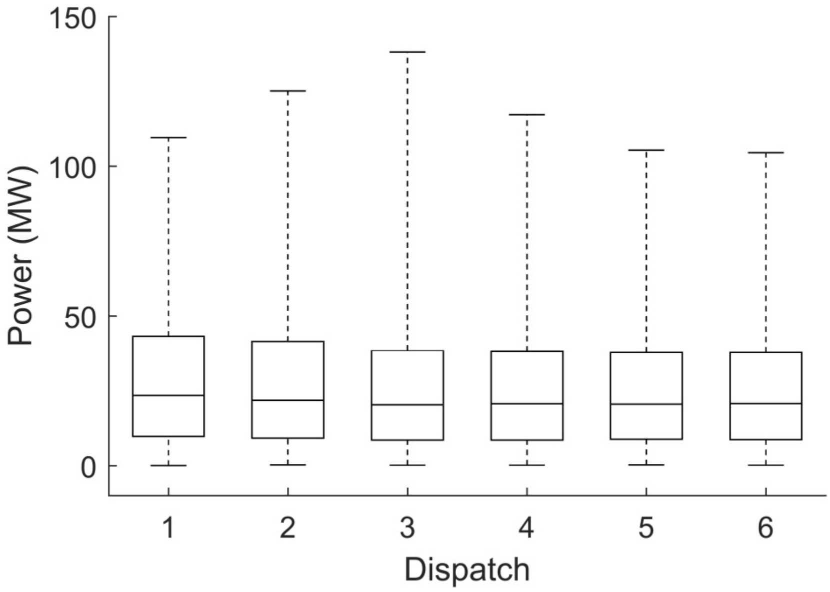

Figure 3.19: Distribution of the total change in dispatched generation for each dispatch in the trading period, i.e. dispatch instruction 1 is sent at the start of the trading period, 2 is sent five minutes after the start, etc. The distribution is presented as a box and whisker plot; the line through the center of the box is the median, the top and bottom of the box are the 75th and 25th percentile respectively, and the ends of the whiskers are the 1st and 99th percentiles. This data is from dispatch instructions from the start of 2013 to the end of 2014, provided by Transpower, however to produce a plot with six dispatch instructions, only trading periods that had six dispatches were counted.

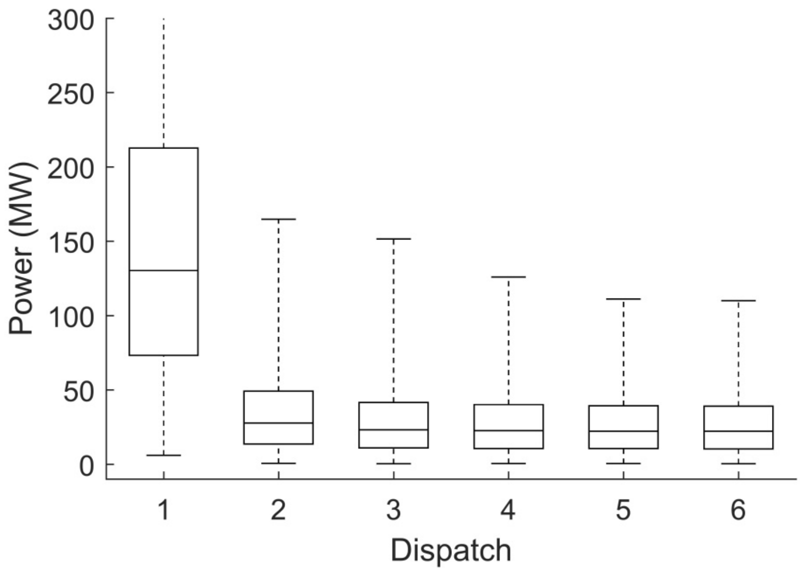

Figure 3.20: Distribution of the absolute change in dispatched generation in the trading period. The absolute change is the total movement, e.g. if Manapouri is instructed to decrease by 105 MW and Waitaki is instructed to increase by 100 MW, then the absolute change is 205 MW. This plot used the same data as Figure 3.19. Notice that the distributions of dispatches 2 to 6 of Figure 3.19 are similar to the distribution of dispatches 2 to 6 of this figure, thereby implying that these dispatched are mostly an adjustment of the marginal generator. Secondly the 99th percentile of dispatch one is 517.7 MW.

4. Generation Dispatch for Different Scenarios

A simulation of how changing penetrations of wind generation adjusts the dispatch is required to determine changes in inertia, droop, and the largest contingent risk on the power system. All these results are needed to estimate the demand for reserves. This section explains the simulation, the assumptions made, and presents some of the results. Further details about the simulation are found in Appendix C and D, and further details about the results are found in Appendix E.

The simulated dispatch process works by replacing current thermal generators with new wind generation. There are eight scenario, starting with an extra 500 MW up to 4000 MW in 500 MW steps of new wind generation. When the instantaneous wind output is too high, wind generation is curtailed so that must-run generation and hydro generation can still produce electricity.

4.1. Dispatch Process

The dispatch process starts by considering the demand profile for which generation is dispatched. This simulation did not use a future scenario for demand for several reasons, but utilized an historical demand profile.

- The purpose of this report is to focus on the impacts of wind generation, and to isolate these impacts from possible future changes in demand. A single historical demand profile was utilized, i.e. the demand from 2013 to 2015 inclusive.
- It is best to consider the power system at its most lightly loaded condition as this provides the worst case scenario for determining the impacts of reduced inertia. Assuming that electricity demand is only going to increase in the future, the historical scenario provides this worst case scenario.
- The historical demand profile provides the easiest means of obtaining high resolution demand data at 30 minute resolutions.

The process of modelling how future scenarios of wind generation change historical dispatch has three steps.

4.1.1. Must-Run Generation

There is a large amount of generation that is not able to change when it runs, such as geothermal, run-of-river hydro, cogeneration and current wind generation and is called must-run generation. Hence in this dispatch simulation this generation is dispatched at its historical output. However, there is one limitation, as there are several run-of-river stations with small reservoirs that allows them to adjust power output throughout a single day. Limiting the output of these power stations to their historical level limits their ability to manage changes in future wind generation. For example, most run of river generation will coincide peak generation with the demand peaks in the morning and the evening, but with future wind generation the morning peak may become less critical as there may be more wind generation in the morning, and the evening peak may become more critical as the wind wanes. However, the must-run dispatch in this simulation is not adjusted.

4.1.2. New Wind Generation Replacing Thermal Generation

It is assumed that the expansion of wind generation in New Zealand will directly result in the retirement of thermal generation in New Zealand. Therefore, in this simulation, every unit of wind energy will displace one unit of thermal energy in the dispatch. However, wind generation is not a consistent source of energy and thermal generation can only be removed on the days when there is a lot of wind generation.

Thermal units once started tend to run for several days, as shown in Figure 4.1, to avoid significant starting and stopping costs. Therefore to retain this constraint, the option for thermal generators to run is limited to a one day option, instead of the one trading period option for hydro generation. The profile of each one day option at half hour resolution is derived from historical thermal generation time series. The time each day option starts is at midnight just before minimum demand around 2 to 4 am; this is to coincide with the likely time thermal generators will startup or shutdown.

4.1.3. Dispatch of Hydro Generation

The five remaining hydro schemes are dispatched to satisfy the difference between the demand and the rest of the dispatched generation for every trading period. These schemes are the Waikato, Waikaremoana, Waitaki, Clutha, and Manapouri. The dispatch keeps the schemes within their operational limits, and tries to minimise the deviation in lake storage from historical levels. If there is an overabundance of new wind generation, wind generation is curtailed. The simulation assumes the same reservoir management policy on the timescale from weeks to years.

4.2. Resultant Changes in Generator Operation

Although this simulation has several limitations as explained above, and does not solve for the optimal energy cost, it does provide a likely dispatch of generation. To show this and explain the impacts new wind generation has on generator operation, the changes in thermal and hydro generator operation is calculated (must-run generation is unchanged). Then the energy balance between thermal generation and new wind generation is used to show possible consequences of new wind generation on the energy market.

4.2.1. Thermal Generation

The results of new wind generation on the operation of thermal generation is seen by comparing Figures 4.1 to 4.3. In Figure 4.1 the historical operation of thermal units is shown by a dark vertical line representing the running of that unit for that day. The Combined Cycle Gas Turbines (CCGT) units of Southdown (SWN0), Otahuhu (OTC), Taranaki (TCC), and Huntly (HLY5) consistently run over periods of weeks, with only SWN0 showing a large number of isolated days. The Open Cycle Gas Turbines SWN5, McKee (MKE), HLY6, Stratford (SFD21 and SFD22) have greater flexibility in operation. The last OCGTs, Kapuni (KPI) has the greatest consistency of the OCGTs, and the Rankine units of Huntly (HLY1 to HLY4) also show longer periods of operation. With 2000 MW of new wind generation, Figure 4.2, no thermal generator can avoid isolated days of operation, this is consistent with high wind generation on some days but little wind power on others. By 4000 MW of new wind generation, Figure 4.3, some of those isolated days have been removed, but some more are created.

To carefully interpret the results, several thermal units have exited the market since 2015: Southdown, Otahuhu, and Huntly Units 3 and 4. The need for these units in the simulation under high wind penetration scenarios does not necessarily imply that they should have remained, but rather it is a limitation in the simulation from using historical data.

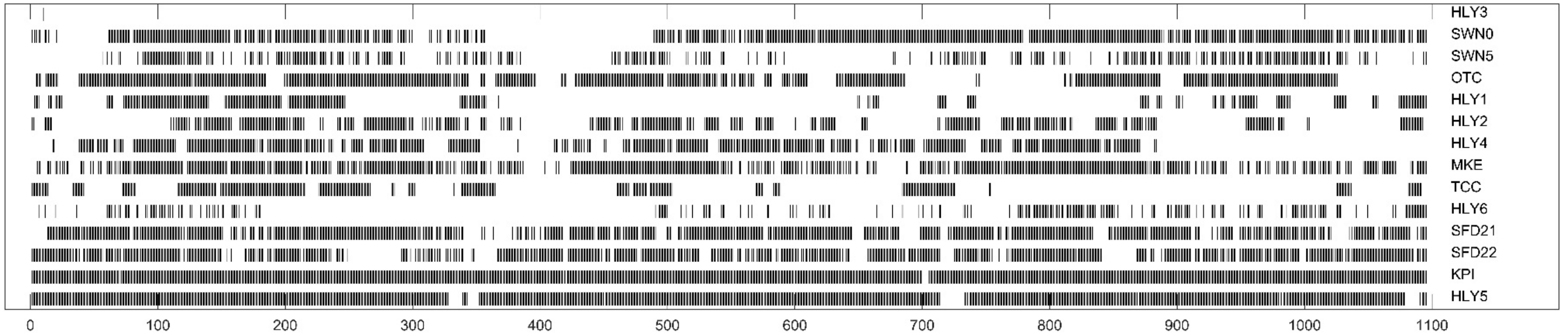

Figure 4.1: Profile of historical thermal generation by day, a black vertical line means that the thermal generator ran for that day. Day one is for the 1st December 2012, and the last day, 1095 days later, is the 30th November 2015. HLY, Huntly; SWN, Southdown; OTC, Otahuhu; MKE, McKee; TCC, Taranaki Combined Cycle; SFD, Stratford; KPI, Kapuni.

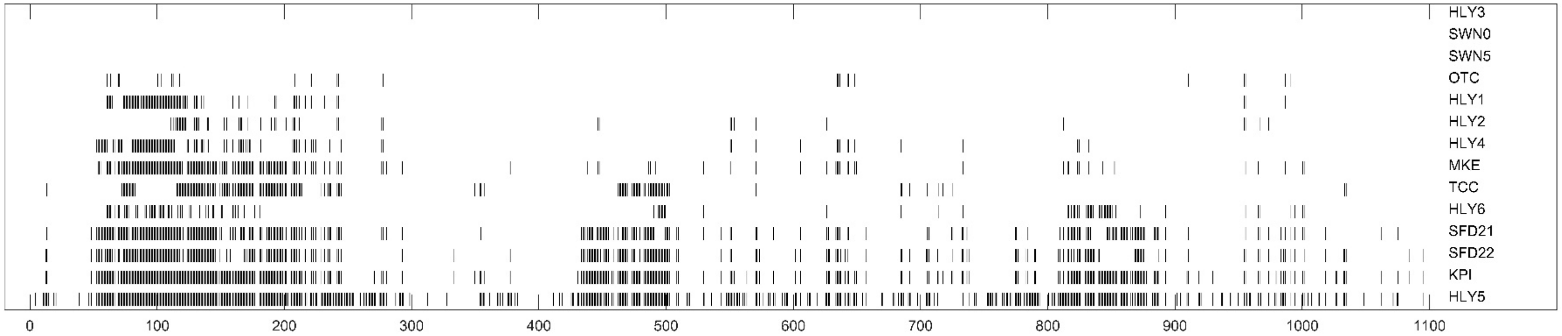

Figure 4.2: Profile of thermal generation with 2000 MW of new wind generation.

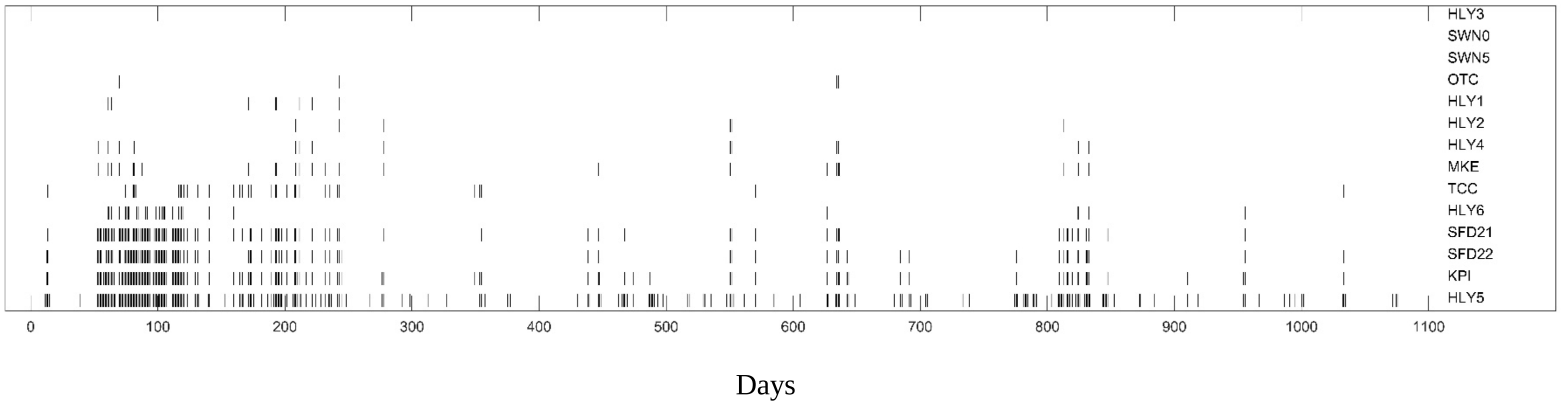

Figure 4.3: Profile of thermal generation with 4000 MW of new wind generation.

4.2.2. Hydro Generation

The change in operation of hydro generation is mainly the greater use of its operating range consistent with managing a more variable wind generation, Figures 4.4 to 4.8, while still retaining its general profile. The ability of the hydro dispatch to follow discrete generation levels for the Waikaremoana and Manapouri power stations has been reduced. There are also greater periods of time when hydro generation is at its minimum. It is unsure whether these schemes can maintain these durations at the minimum because of canal and river dynamic requirements. Overall the results are sufficient for the purposes of this analysis.

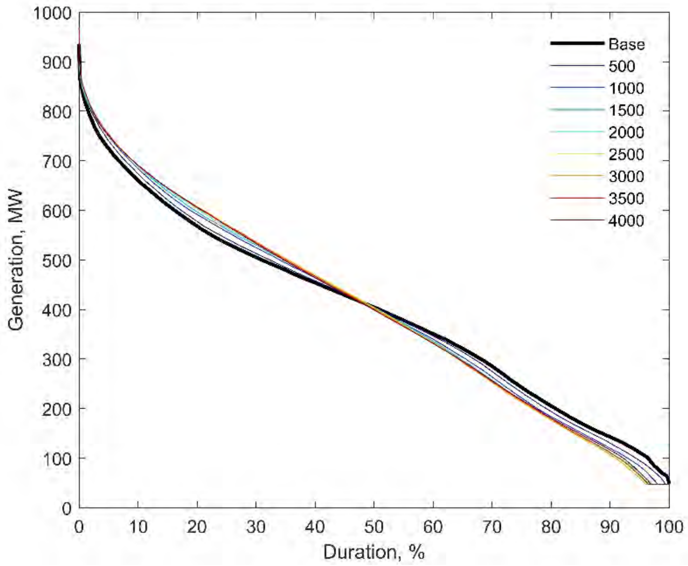

Figure 4.5: Waikato Scheme Duration Curve with increasing penetrations of new wind generation.

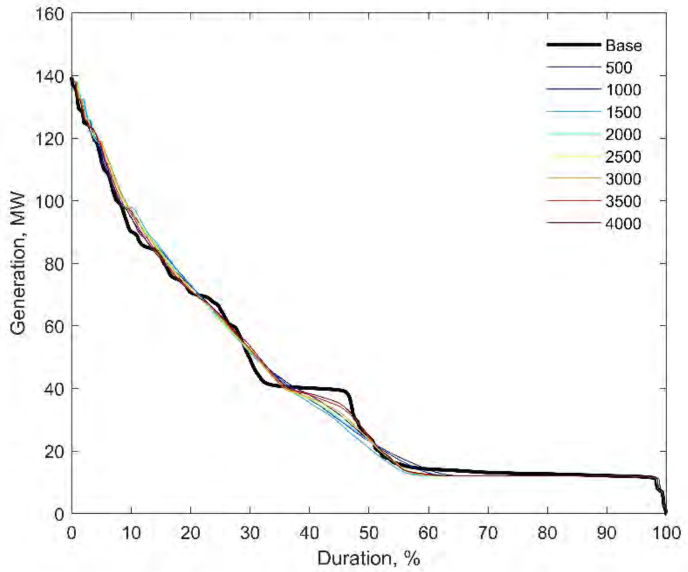

Figure 4.4: Waikaremoana Scheme Duration Curve.

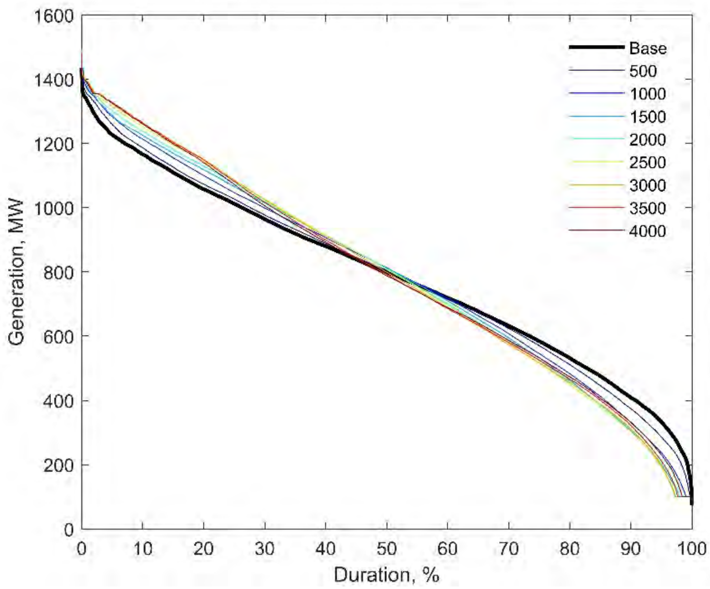

Figure 4.7: Waitaki Hydro Scheme Duration Curve.

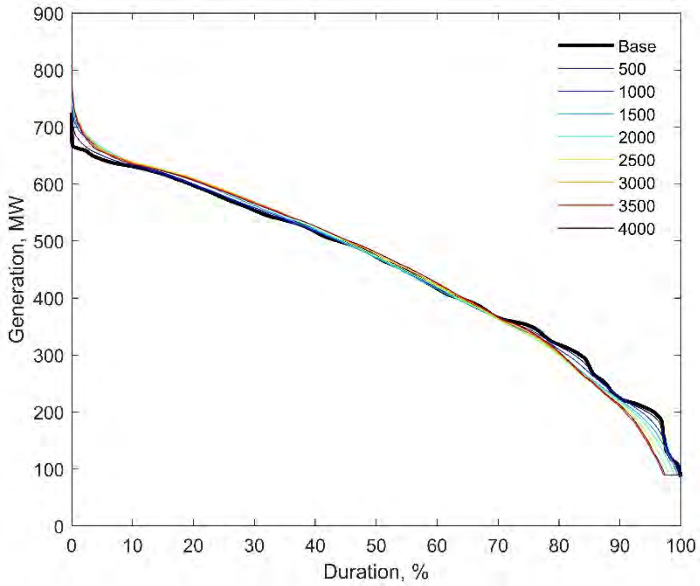

Figure 4.6: Clutha Hydro Scheme Duration Curve.

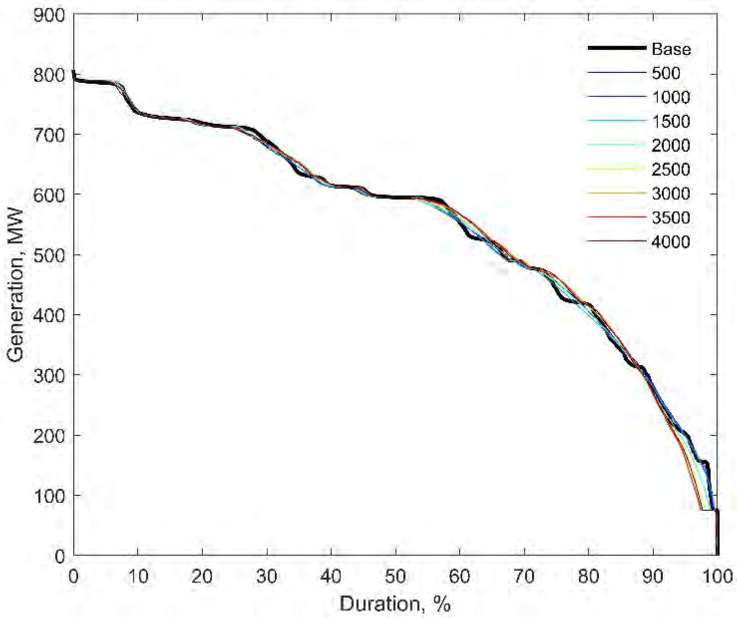

Figure 4.8: Manapouri Power Station Duration Curve.

4.2.3. Energy Balance

There are periods when the wind is not blowing and thermal generation is required. For the higher penetrations of wind generation, when wind and must-run generation exceed the total demand, wind energy has to be curtailed. The contribution of thermal and wind energy to the demand for changing wind energy penetrations is analysed in the dispatch simulation, Figure 4.9. There is a point at roughly 1500 MW of new wind generation where some energy has to be curtailed. The exact point when this occurs varies depending on the hydrology of the year and the availability of capacity. The consequence of curtailing wind energy is that the cost of wind energy increases, and the difficulty of arriving at 100% renewable energy through wind generation alone is apparent. To arrive at a state of 100% with wind generation, without formally considering the cost of each option, it appears that the electricity market will have to deviate from the most economic option of keeping some thermal units, and have a combination of spilling wind energy and building energy storage. However full economic analysis has to be completed to determine the best option.

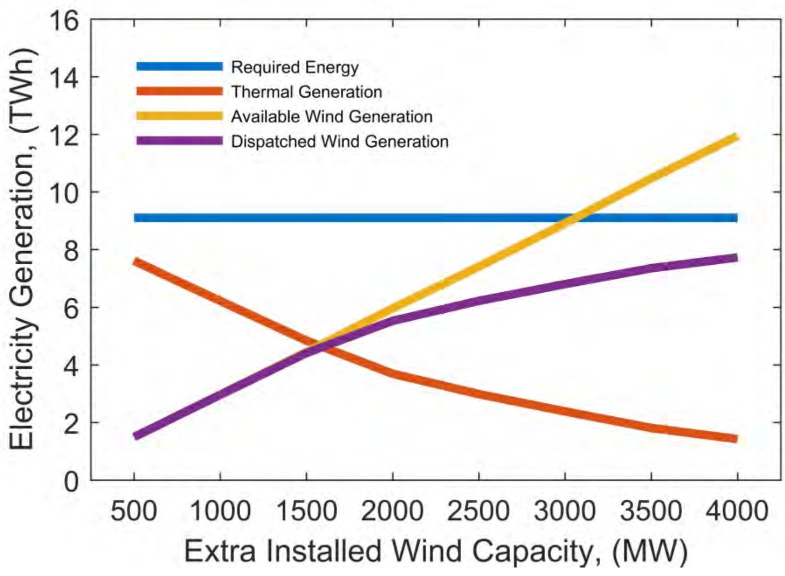

Figure 4.9: The energy balance between dispatched thermal generation and new wind generation in order to satisfy the historical energy requirement for thermal energy in 2013.

5. Impacts of Wind Generation on the Power System

Wind generation operates differently to conventional generation, and may have a negative impact on the overall management of the electricity grid. This section analyses the impacts of wind generation on frequency management. Wind generation's main impacts are the result of decoupling of grid frequency from turbine shaft speed, the uncertainty in the fuel source, and the adverse economics of spilling wind. The first two causes create four consequences for the power system: reduced inertia, reduced droop, increased variability, and unpredictability. The requirements for reserves are analysed in relation to these four consequences.

5.1. Inertia

This section looks at how wind generation changes inertia. Wind generation generally cannot provide an inertial response, i.e. for any imbalance between the total mechanical power supplied into the system and the total electrical power drawn, the energy stored in the rotating mass of the wind turbine does not help to satisfy the imbalance, rather the imbalance is satisfied through the kinetic energy stored in synchronous generators (conventional generator). This lack of inertial response is due to the decoupling of the grid frequency from the turbine speed through the power electronic converter. Decoupling allows the wind turbine to optimally determine the turbine speed for any wind speed, and therefore maximize power generation. Since wind generation is likely to replace generation with inertia, the total inertia of the system will decrease as wind generation capacity increases.

The impact that wind generation has on inertia is firstly calculated on a historical basis, and secondly the impacts are determined for future scenarios. The historical impacts of wind generation are assessed by determining the correlation of inertia and wind generation, Figure 5.1. There is a negative correlation between inertia and wind generation. The slope of the line of best fit is -4.7 MWs per MW of wind generation, which is comparable to the average inertia per MW of generation capacity of 5.1 MWs/MW. It is noticed that inertia is weakly correlated with wind generation, as the primary influence is from demand across various time ranges, because demand primarily determines how much conventional generation is synchronised to the grid.

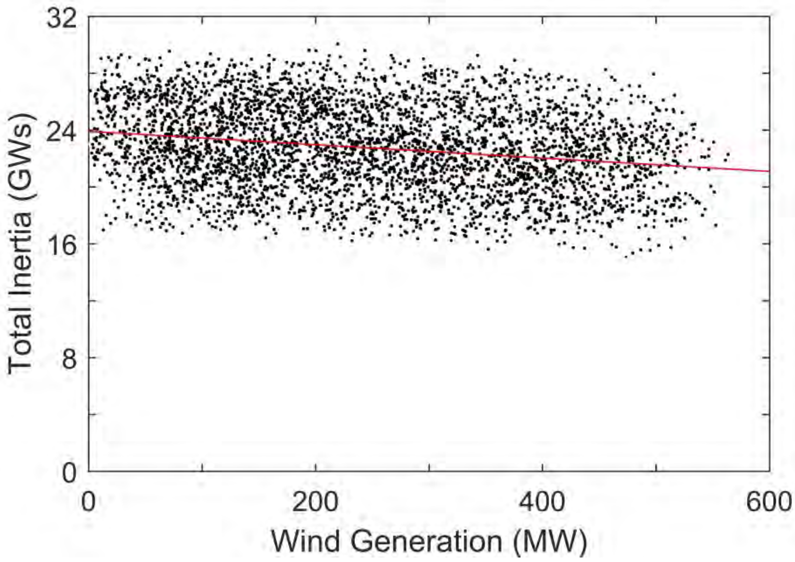

Figure 5.1: The historical correlation between the instantaneous wind generation and the total inertia for New Zealand, over 2014.

To assess the impact of more wind generation capacity on inertia, the dispatch of generation is recalculated for different wind generation scenarios, for loads from 2013 to 2015. These scenarios range from 500 MW of extra capacity to 4000 MW, spread across each island; more detail about the scenarios is given in Appendix D. The dispatch process recalculates the requirement for thermal energy and shifts hydro generation within capacity limits; more detail about the dispatch is given in Appendix C. The dispatch does not consider changes in reserve requirements or transmission constraints, but is limited to the balance of energy.

The dispatch process assumes energy produced by wind generation will replace energy produced from thermal generation, because of the desire to reduce greenhouse gas emissions, and the recent decommissioning of thermal units. The dispatch process is designed to ensure energy from hydro generation will not be spilled, to minimise waste from conventional plant. For the larger wind generation scenarios, where there is more energy generation from wind than what has been historically produced by thermal units, wind generation is spilled. Capacity constraints, in the dispatch process, can cause the spillage of wind generation as well. Since wind generation at any one instant may be greater than what thermal generation was, hydro generation reduces output; however, if hydro generation is running at a minimum then wind is spilled. This also has an impact on the distribution of inertia. The effects of wind on the distribution of inertia are presented in Figures 5.2 to 5.5.

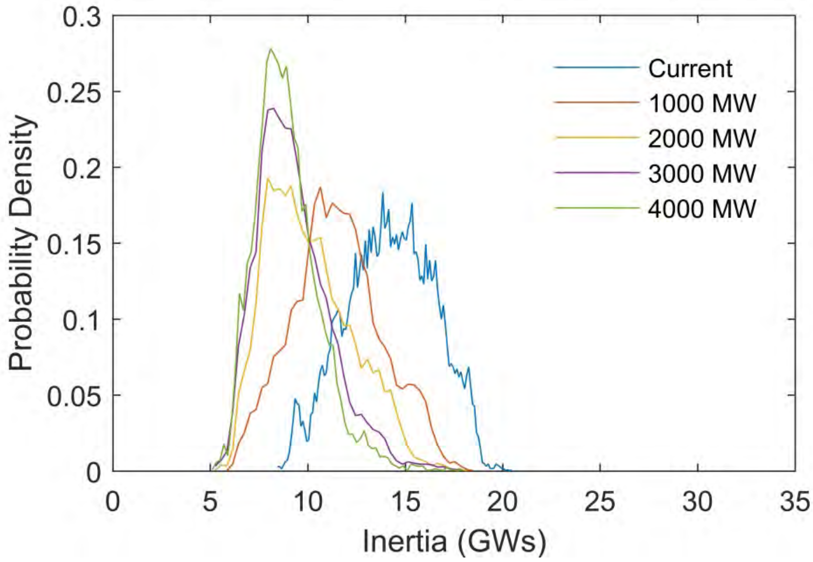

Figure 5.2: The changing distribution of North Island inertia as the capacity of wind generation increases from 1000 MW to 4000 MW.

The result show that the North Island inertia reduces as thermal generation is removed, and that South Island inertia remains relatively unchanged as there is no thermal generation in the South Island. However, the South Island inertia distribution has spread slightly, and the lower limit has reduced from about 5,000 MWs in the historical case to about 4,000 MWs with 3,000 MW of extra wind generation. The North Island has seen a far larger reduction in the minimum inertia, from 9,500 MWs to 5,500 MWs, and the total inertia for both Islands has reduced from 17,000 MWs to 10,000 MWs. Periods of minimum system inertia are the most important, as they have the potential to experience high rates of change of frequency stemming from a contingent event.

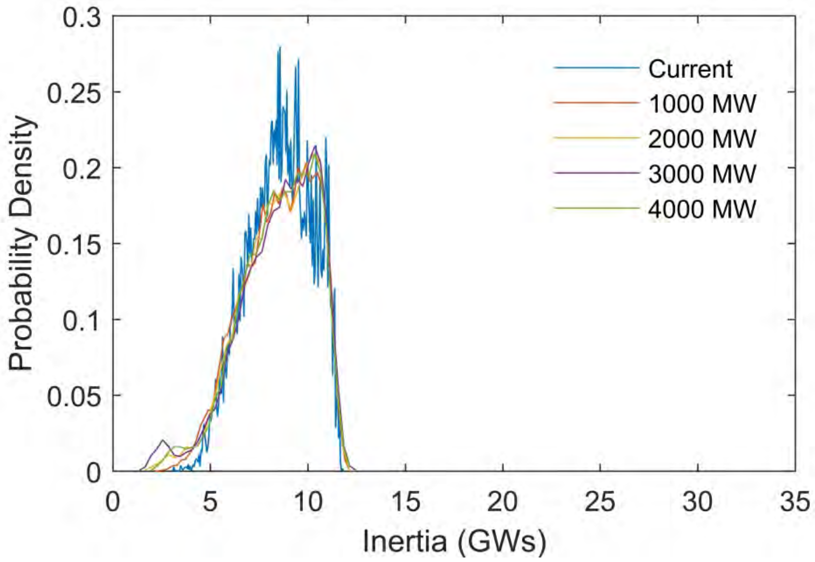

Figure 5.3: The changing distribution of South Island inertia as the capacity of wind generation increases from 1000 MW to 4000 MW.

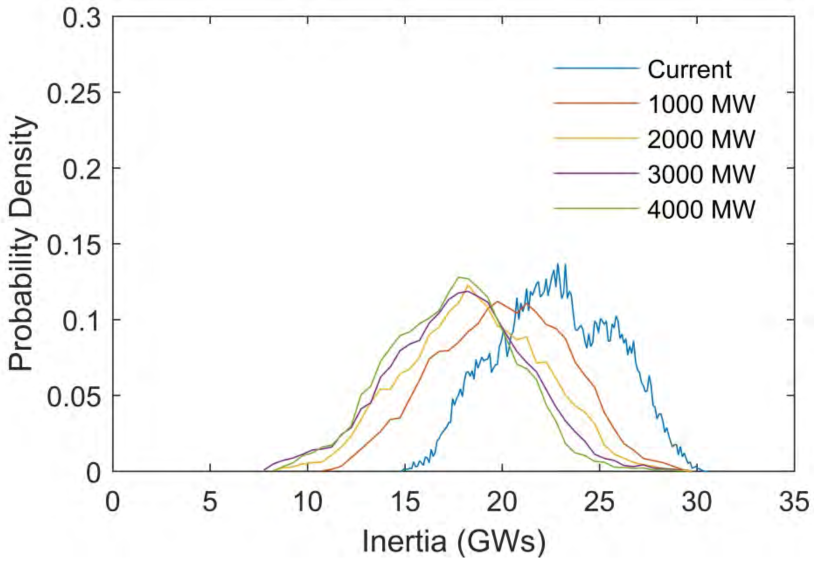

Figure 5.4: The changing distribution of New Zealand inertia as the capacity of wind generation increases from 1000 MW to 4000 MW. The primary change is a result of North Island changes.

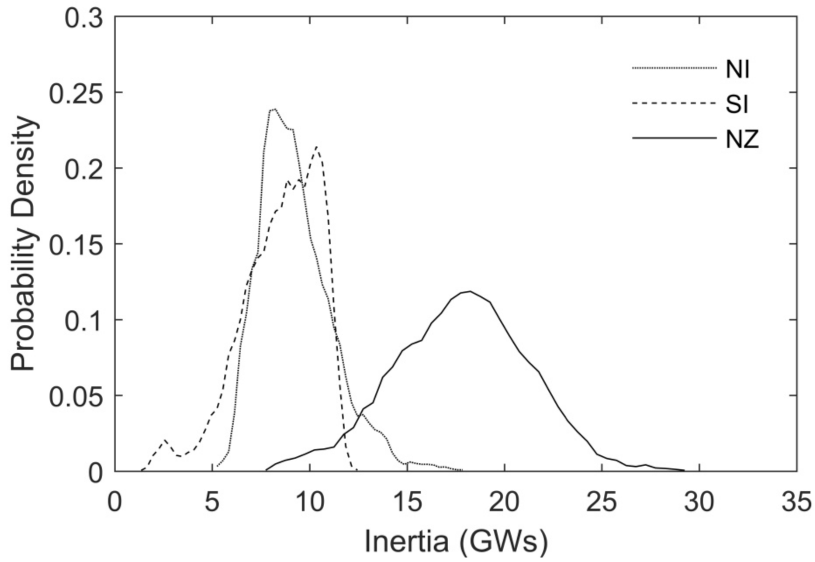

Figure 5.5: A comparison between North Island, South Island, and total New Zealand Inertia for the case of 3000 MW of installed wind generation. The total North Island inertia is now comparable to the South Island.

5.2. Droop

This section looks at the impact wind generation has on droop. Wind generators seek to maximize economic output, aiming to maximize the amount of generation that can be taken out of the wind. Therefore, they normally have no capacity to increase output, and no incentive to reduce generation to supply reserves, and are unable to provide droop, without spilling energy. As wind generation replaces other generation, droop will decrease when wind generation increases output, Figure 5.6.

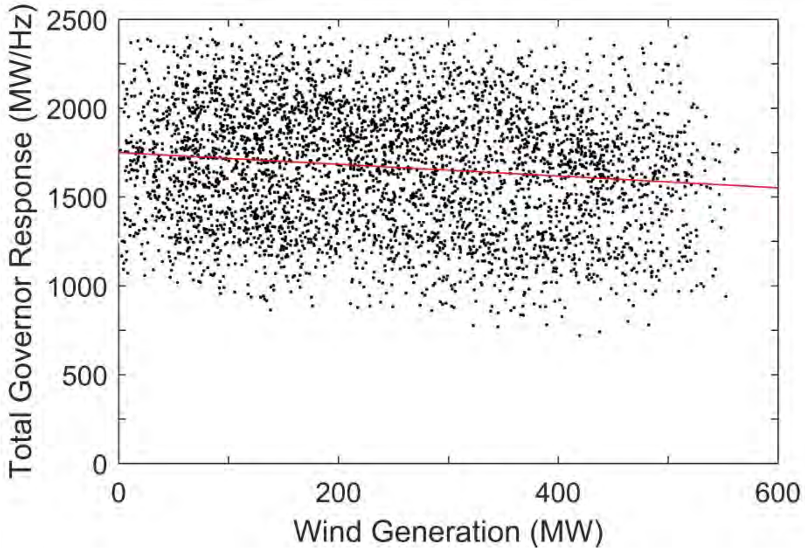

Figure 5.6: The historical correlation between the instantaneous wind generation and the total droop for New Zealand, over 2014.

The total droop during the year will remain constant for increasing capacity of wind generation, because total droop is determined by how much hydro generation there is, which will not decrease as wind generation is installed. However, the distribution of droop may spread, as the times of high wind generation with low hydro generation and vice versa will become more pronounced with more installed wind generation. To assess this impact, the same dispatch process used for assessing the impact of wind generation on inertia is applied for droop. The results of this analysis are shown in Figures 5.7 to 5.10. The results show an imperceptible change in droop with increasing wind capacity.

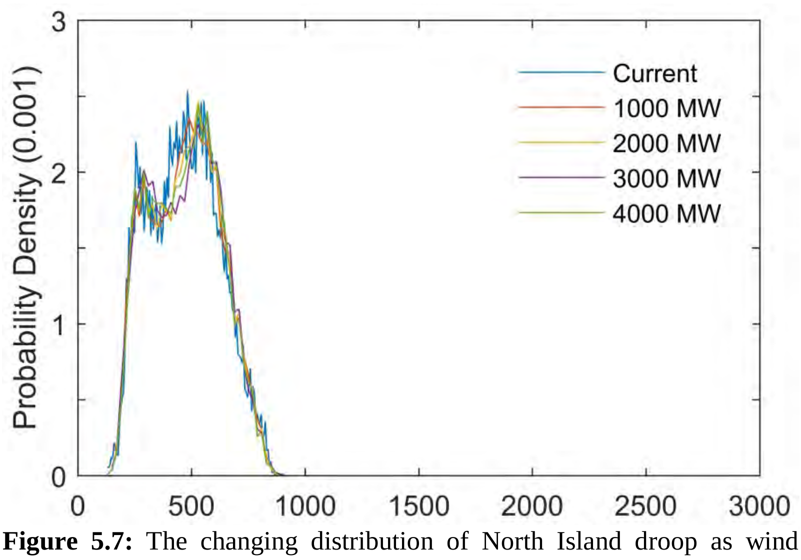

Figure 5.7: The changing distribution of North Island droop as wind penetration increases from 1000 MW to 4000 MW. The dispatch process does not show significant changes in droop.

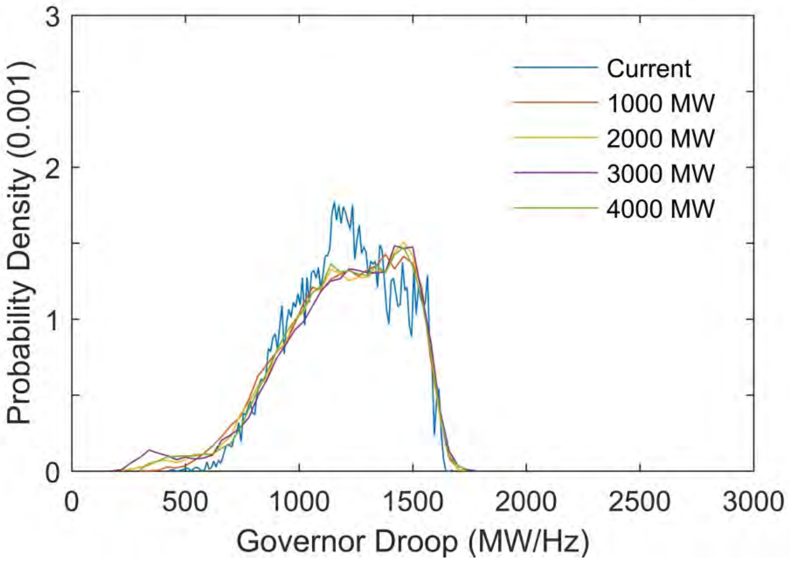

Figure 5.8: The changing distribution of South Island droop as wind penetration increases from 1000 MW to 4000 MW.

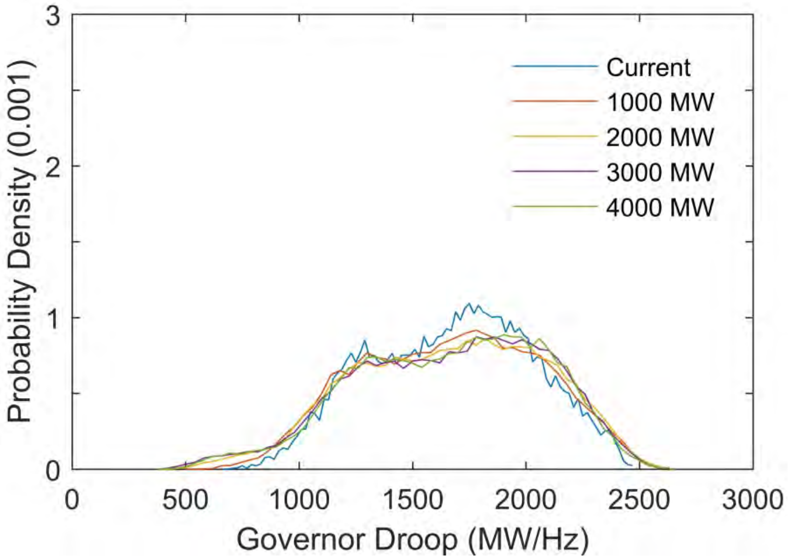

Figure 5.9: The changing distribution of total New Zealand droop as wind penetration increases from 1000 MW to 4000 MW.

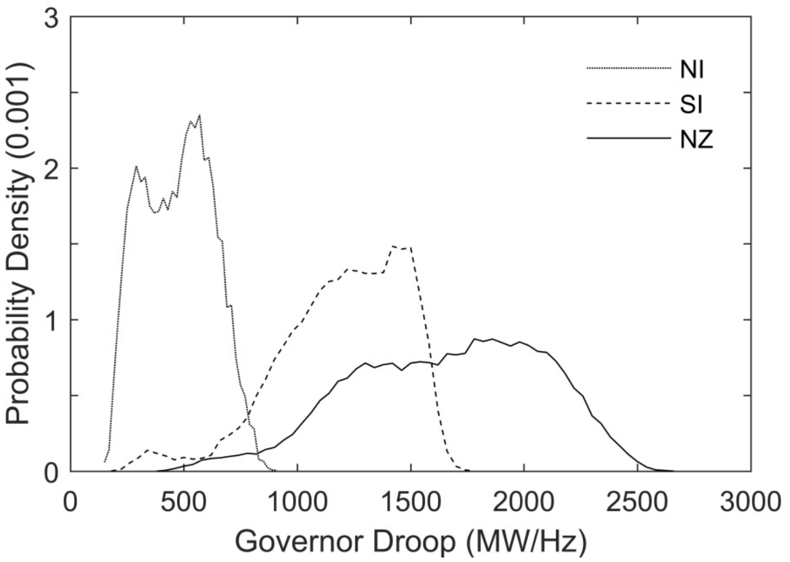

Figure 5.10: A comparison between North Island, South Island, and total New Zealand droop for an increase in wind penetration of 3000 MW.

5.3. Variability

Wind generation, when maximizing generation output, produces an inherently variable power output, dependent on the wind speed. This variability is managed by regularly adjusting the dispatch of other generation. The dispatch process of the System Operator (SO), assumes that each wind farm will produce the same output as it did one minute before the dispatch instruction was sent, and maintain that level of generation for the next five minutes. However, the wind farm does not maintain this level of generation. If the wind speed changes, then it produces a power imbalance. The variability of the wind generator is the possible change that could occur over 5 minutes from the start to the end of the dispatch period. For example, the variability is shown for the West Wind farm during a half hour on the 1st January 2015, 8:00 am, Figure 5.11. Wind generation does not deviate from the dispatch significantly, but does have a consistent bias if generation is consistently ramping in one direction, which is seen in the last 15 minutes of the half hour.

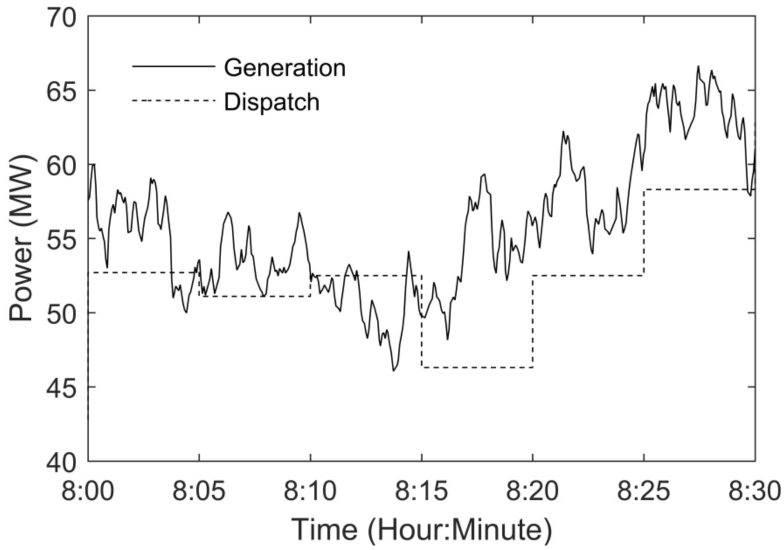

Figure 5.11: A comparison between the actual generation of West Wind farm and the anticipated generation from the wind farm used in the dispatch, for the 1st January 2015, 8:00 am.

To determine the impact of new wind generation on variability, the current variability of wind generation is calculated and then extrapolated. Current variability is analysed by creating a time series of the error between the dispatch and actual generation for each major New Zealand wind farm. The distribution of wind power variation relative to wind farm capacity is shown in Figures 5.12 and 5.13, and Table 5.1. A single wind farm can have an error quite often extending past 3% of capacity. However, as variability of wind farms combine their relative error reduces. This is seen for combinations of wind farms shown in Figures 5.14 and 5.15.

There is an approximate square root relationship between the standard deviation of error and the wind generation capacity, as shown by the general trend of Figure 5.14. This is due to the uncorrelated nature of wind generation at 5-minute temporal resolutions, i.e. for two random processes, $x(t)$ and $y(t)$ with equal standard deviation $\sigma_X = \sigma_Y$, the standard deviation of the summation is:

$$\sigma_{X+Y} = \sqrt{\sigma_X^2 + 2\sigma_{XY} + \sigma_Y^2} = \sqrt{2}\sigma_X \ \ when\ \sigma_{XY} = 0 \tag{5.1}$$

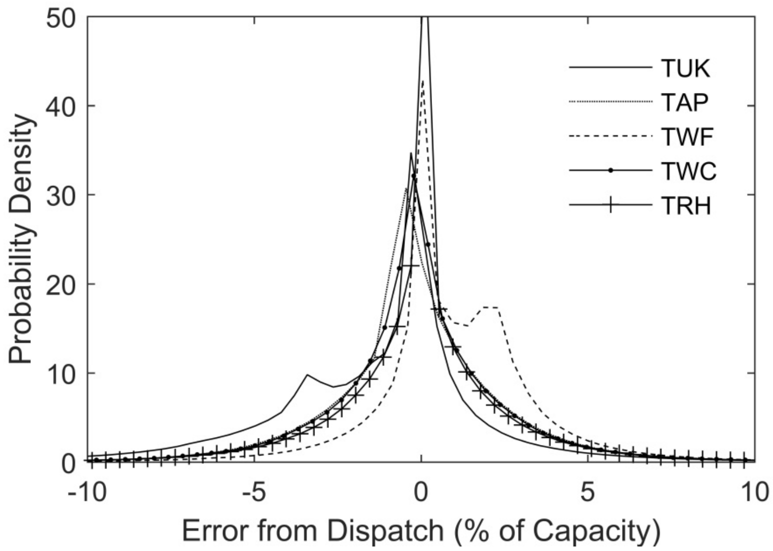

Figure 5.12: The distribution of error between the actual generation from selected New Zealand wind farms and the anticipated generation.

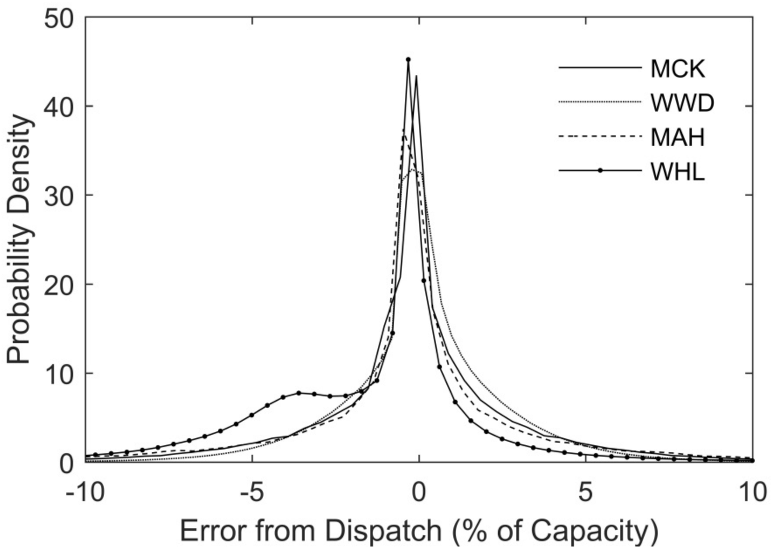

Figure 5.13: The distribution of error between the actual generation from selected New Zealand wind farms and the anticipated generation.

Table 5.1: The standard deviation of error between actual generation and anticipated generation (dispatch) for New Zealand wind farms during 2013 and 2014.

Wind Farm		Capacity	Standard Deviation, σ	
Name	ID	(MW)	(MW)	%
Te Uku	TUK	65	2.45	3.77
Te Apiti	TAP	91	2.76	3.03
Tararua I and II	TWF	73	2.29	3.14
Tararua III	TWC	93	3.18	3.42
Te Rere Hau	TRH	49	1.51	3.07
Mill Creek	MCK	60	2.78	4.63
West Wind	WWD	143	3.78	2.64
Mahinerangi	MAH	40	2.94	7.35
White Hill	WHL	58	2.27	3.91

The uncorrelated nature of wind generation at short temporal scales, and particularly in New Zealand, has been demonstrated by Dougal McQueen in the scaled correlations of Chapter 4 of his Thesis (McQueen, 2016). He shows that for any two wind turbines located close together there is no correlation at time scales less than 1.4 minutes, and it only increases slightly within a 5-minute period if they are close together. Therefore, it can be assumed that variability will follow square root relationship with increasing wind capacity, which is demonstrated by fitting a curve to Figure 5.14. Extrapolating the best fit line, the expected variability of future wind generation scenarios is estimated, Table 5.2.

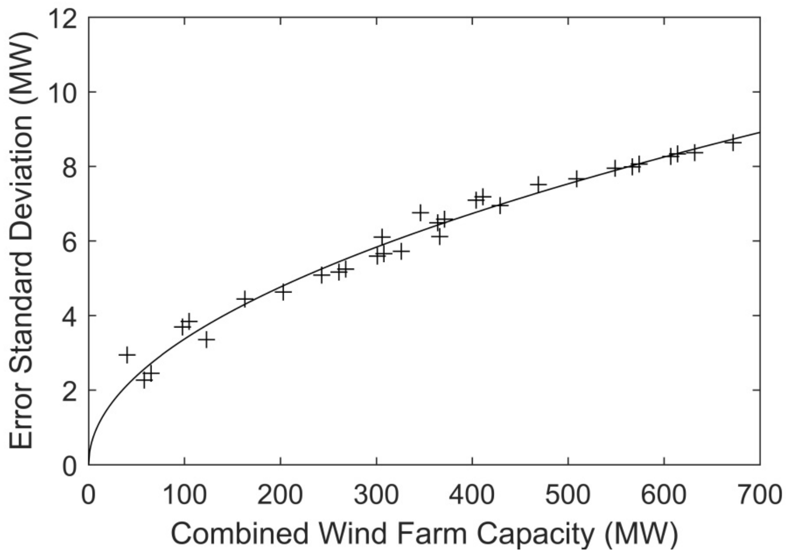

Figure 5.14: The impact of increasing wind farm capacity on the standard deviation of the error between actual wind generation and the anticipated wind generation (dispatch). The best fit line (solid black line) has the equation $y = \alpha\sqrt{x}$, where α is $0.34MW^{0.5}$.

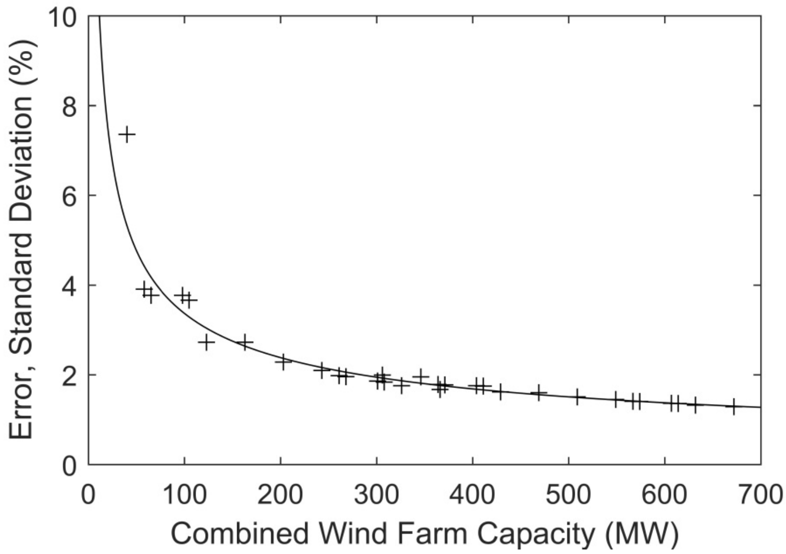

Figure 5.15: The relative impact of increasing wind farm capacity on the standard deviation of the error between actual wind generation and the anticipated wind generation (dispatch). Derived from actual wind farm generation data from 2013 to 2014.

The standard deviation of the wind variability only characterises one important aspect of the wind variability, however consideration for speed of variation is required as well, not just the magnitude. The speed of the variation is analysed by looking at the spectral decomposition, Figure 5.16. The slope of the spectral lines from 10^{-3} to 5×10^{-2} Hz (16.7 minutes to 20 seconds oscillations) are well predicted by Kolmogorov's theorem for the energy of spectral components of the wind speed, as seen by the slope closely following a gradient of $-5/6$ decade MW per decade Hz. For spectral components from 5×10^{-2} to 1 Hz (20 seconds to 1 second) there is an apparent tapering in signal strength from that which is expected from Kolmogorov's Theorem; this is likely a result of finite response time of wind turbines, which smooth out the very fast variations, however it is difficult to separate this from other causes, such as noise created by storing and processing the data.

Table 5.2: The variability of wind generation as more wind capacity is added to the system.

	Wind Capacity (MW)	Variability, σ (MW)
Current Capacity	672	8.6
Scenarios (+1000)	1672	13.8
(+2000)	2672	17.4
(+3000)	3672	20.4
(+4000)	4672	23.0

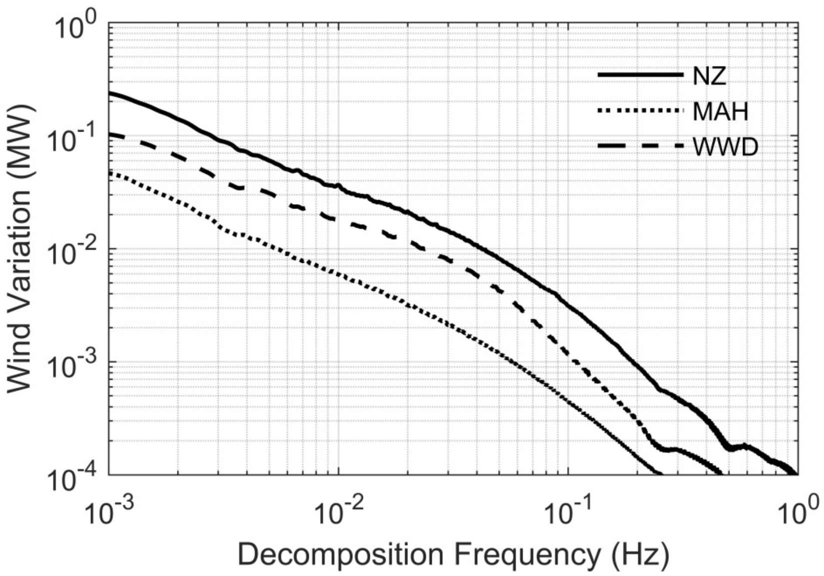

Figure 5.16: Spectral decomposition of wind farm variability, equivalent to the square root of the Power Spectral Density. NZ, New Zealand; MAH, Mahinerangi; and WWD, West Wind. The data was from 2013 and 2014.

The uncorrelated nature of power output from wind farms at these time scales also preserves the general spectral profiles of each wind farm, and the summation of power outputs from several wind farms. Therefore, extrapolating the spectral profiles for scenarios with greater capacity can be achieved by scaling the variation, where it is scaled proportional to the increased standard deviation of the variation.

5.4. Unpredictability

In the operation of the power system, predictions of wind power output are made so that the operator can coordinate the system: whether that is at the 5-minute timescale so that wind generation is dispatched, or a longer timescale so that security checks are performed. Predictions at this timescale are made on a persistence forecast, i.e. the current generation output is the best prediction of future output. Therefore, error in the persistence forecast is characterised by the distribution of changes in power output between two points in time separated by the forecast horizon, which is also equivalent to the distribution of ramp rates. This section mainly describes the distribution of ramp rates; however, this information can also be applied when considering the impacts of prediction errors on system operations.

This section characterises the impact of added wind generation on the distribution of ramp rates. The impact of current operational wind farms is described to provide a base case for future scenarios. Each future scenario is simulated from historical wind speed data that is modelled to produce a wind power time series while retaining the temporal and spatial properties of wind. This retains the characteristics of wind power output that give rise to large fluctuations in power, such as large weather fronts tracking across the country causing a synchronized increase in power output of closely located wind farms. A further explanation of the simulation process is provided in Appendix F.

With current New Zealand wind farms, the sizes of the largest ramping events in 30 minutes are between 200 to 250 MW, as shown in Table 5.4. The largest drop is 230 MW over 30 minutes followed by an increase of 252 MW after 20 minutes roughly; this pattern implies that a large number of wind turbines in the Tararua Range experienced over-speed, disconnected, and progressively returned to normal once the wind speed reduced. This event occurred on the 20th April 2013, where a large storm battered New Zealand for several days, causing significant damage (NIWA, 2013).

Table 5.3: Largest total wind generation changes from December 2012 to April 2015. The time is from the start of the ramping. This data is from the 8 largest New Zealand wind farms excluding Mill Creek, for a total capacity of 612 MW.

Positive Ramp			Negative Ramp		
Size (MW)	Date	Time	Size (MW)	Date	Time
30 Minutes Duration					
252	20/4/2013	7:42	-230	20/4/2013	6:50
227	17/8/2013	3:32	-208	17/1/2013	18:52
222	30/12/2013	17:02	-202	25/3/2014	20:57
1 Hour Duration					
261	30/12/2013	16:55	-272	17/1/2013	18:27
260	20/4/2013	7:35	-258	20/4/2013	6:35
228	27/4/2015	13:05	-238	25/3/2014	20:30
2 Hours Duration					
327	7/1/2013	9:35	-299	7/10/2014	0:42
301	6/12/2012	18:30	-289	20/11/2014	2:17
286	14/10/2014	9:50	-282	20/4/2013	6:35

For durations of 2 hours, the largest ramp rates range from 330 MW to 280 MW, a result of the concerted response of multiple wind farms across several geographic regions. In comparison to ramp rates experienced during morning demand peaking, wind generation ramp rates are smaller, where demand ramps in the order of 1,500 MW to 2,000 MW in four hours. However, this is an unequal comparison, as demand follows a highly predictable pattern.

For most of the time the ramp rates do not even closely approach these large rates; more commonly the ramp rates are evenly distributed about zero, with a standard deviation of roughly 50 MW for a 2-hour horizon and 612 MW of installed wind generation. The largest ramp rates are more than six times the standard deviation. The distribution of ramp rates is shown in Figure 5.17. With increasing penetrations of wind generation, the standard deviation of ramp rate distribution is estimated; the results are shown in Figure 5.18. It is evident that the standard deviation does not increase in a linear fashion with increasing installed capacity, but increases with a power somewhere between 0.5 and 1. For example, 2-hour ramp rates increase at a power between 0.73 and 0.83, i.e. $\propto x^{0.73}$, depending on the spatial distribution of the wind farms. This power is quite large when compared to the 5-minute ramp rates, where the power ranges from 0.57 to 0.63; thereby indicating that 5-minute variations are mainly uncorrelated, whereas 2-hour variations tend to have significant dependency.

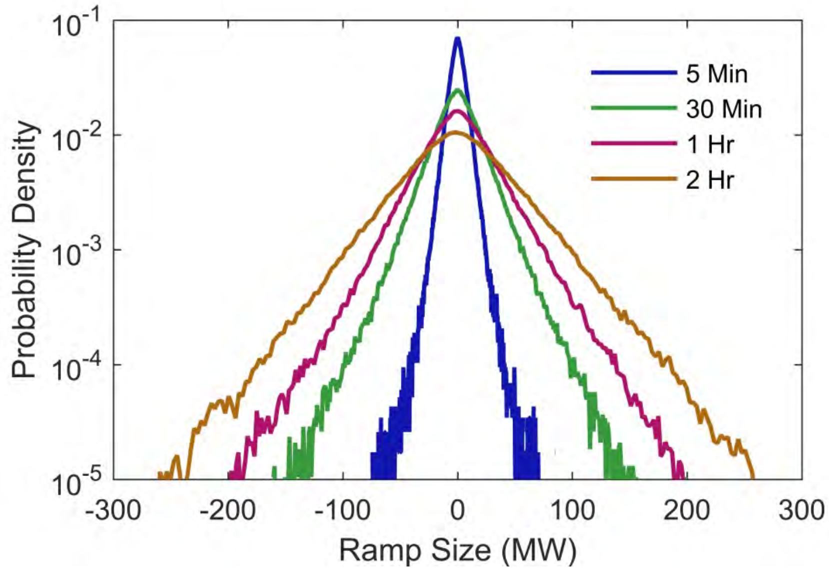

Figure 5.17: Distribution of ramp rates at different time horizons for New Zealand's operational wind farms. The data is from a time period starting from 2013 to the end of 2014. The standard deviations for each time period are 8.2 MW for 5 minutes, 24.3 MW for 30 Minutes, 35.7 MW for 1 hour, and 51.8 MW for 2 hours.

Considering the maximum ramp rates in the 5-minute range, as they have the greatest impact on frequency management, the top 10 largest positive and negative historic events are listed in Table 5.4 for a positive ramp, and Table 5.5 for a negative ramp. This data is derived from Transpower's SCADA system, and the accuracy of the values cannot be guaranteed, and some potential events have been removed because they have lacked quality. For 5 minutes, the largest change in power output was around 120 MW for the period from November 2012 to April 2015. Several of the largest 5-minute ramping events continue for a longer period and give rise to larger events at 30 minutes; however, most are not sustained. Predicting the maximum 5-minute ramp rates in the future with increased penetration is rather difficult, and would be best estimated by coupling a high spatial and temporal, mesoscale, weather model with an accurate wind turbine and wind farm model. This modelling would require significant amount of input with limited return in understanding. Also, an effectively stochastic simulation is available for 5-minute time resolutions, but has limited accuracy (Appendix D). However, an estimate with several assumptions suffices.

In 2005, when the Manawatu wind farms only consisted of Tararua Stage 1 and 2, and Te Apiti, with a combined capacity of roughly 160 MW, there was concern about large fluctuations in output from the 5 to 15 minute range (Transpower, 2005). There were two events of 105 and 109 MW in 5 minutes, roughly 60% of capacity, which were of greatest concern. Since this was such a large proportion of capacity, later the Wind Generation Investigation Project (WGIP) sought to understand what could happen in the future with larger wind capacities. The results from Investigation 2 of WGIP and the Garrad Hassan Report estimated that the change in output for a total of 2250 MW of capacity (Scenario C) would be 155 MW (Transpower, 2007a) (Garrad Hassan, 2007). Scenario C assumed the largest cluster would be 450 MW in the Manawatu.

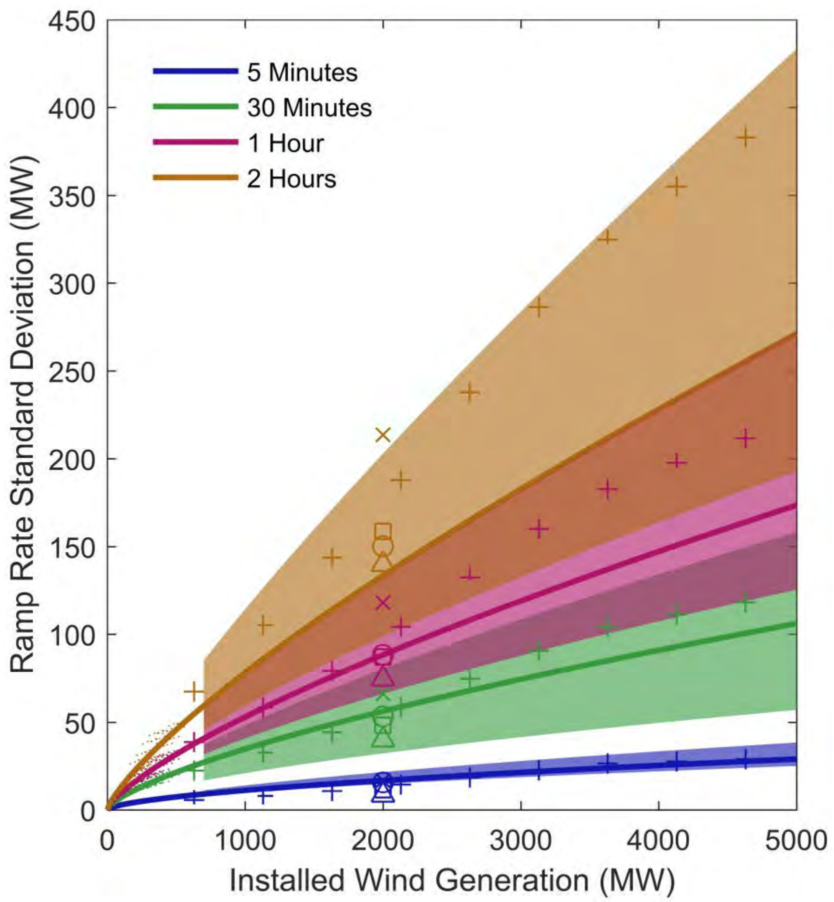

Figure 5.18*:* Predicted standard deviations of ramp rate distributions, for time horizons of 5 minutes, 30 minutes, 1 hour, and 2 hours. The prediction is made by first determining the standard deviation for combinations of currently operating wind farms: the result is seen in the small dots just below 600 MW of installed capacity. A power curve, αx^{β}, is fitted to these data points to extrapolate the expected standard deviation shown by the solid line. The shaded areas are produced by adjusting β to bound variations in the data points. The shaded area models the possible range of values depending on the spatial distribution of the wind farms, e.g. the closer the wind farms are located together, the higher it will be in the range.

The extrapolation is validated by simulations: more detail is provided in Appendix. D. Firstly the four scenarios of Dougal McQueen's thesis are applied: Compact, ×; Disperse, ○; Diverse, □; and Business as Usual, Δ. (NB: the simulation over estimates 2 hour ramp rates by 20%, and under estimates 5 minute ramp rates by 30%, 30 minutes and 1 hour are accurate, Appendix. D). Next a simulation, based from the business as usual case, has been applied in steps from an addition 500 MW to 4000 MW to the currently installed generation.

Comparing events from 2005 and the more recent ones from November 2012 to April 2015, there is not a major difference, even though Manawatu wind farms have increased in capacity to 300 MW, and the total capacity of the 2012 to 2015 analysis data is 612 MW. This is because large fluctuations at 5 minutes only come from fast wind speed changes in small geographical areas, i.e. a cluster of windfarms. This has also been shown for New Zealand by Dougal McQueen, where 5-minute correlations in wind farm output can only be found in geographically close wind turbines. In the future there are proposals for large wind farms, such as the 858 MW Castle Hill wind farm, and the 504 MW Hauauru Ma Raki wind farm, which could be cause for concern. However, it is expected that the 5-minute fluctuations will not be more than 200 MW as installed wind capacity increases 4000 MW on top of the current 690 MW.

Table 5.4: List of top 10 positive ramping events of wind generation, including the same parameters as Table 5.1. ID is an identification of event time, which is listed in Appendix L, with the intention of showing the progression of ramping events from 5 minutes to 30 minutes.

Rank	5 Minutes		10 Minutes		15 Minutes		20 Minutes		25 Minutes		30 Minutes	
	ID	MW	ID	MW	ID	MW	ID	MW	ID	MW	ID	MW
1	1	129	1	167	5	195	5	210	5	222	1	252
2	2	110	8	153	8	192	1	208	1	214	5	227
3	3	103	5	153	1	188	8	205	8	214	11	222
4	4	95	10	148	11	178	11	198	11	206	8	216
5	5	92	11	138	3	160	15	184	15	187	15	210
6	6	88	3	134	10	159	3	166	3	184	21	207
7	7	87	2	122	15	159	19	163	19	182	3	198
8	8	87	12	119	16	144	16	159	21	166	19	187
9	9	87	13	116	17	137	10	158	20	164	22	179
10	10	85	14	115	18	136	20	151	16	163	16	167

Table 5.5: List of top 10 negative ramping events of wind generation.

Rank	5 Minutes		10 Minutes		15 Minutes		20 Minutes		25 Minutes		30 Minutes	
	ID	MW	ID	MW	ID	MW	ID	MW	ID	MW	ID	MW
1	1	-116	1	-144	11	-179	11	-231	1	-231	1	-230
2	2	-108	11	-135	1	-175	1	-225	11	-228	20	-208
3	3	-94	2	-130	15	-137	18	-167	12	-191	18	-202
4	4	-89	12	-121	13	-137	12	-162	18	-185	12	-189
5	5	-84	13	-114	2	-135	14	-154	20	-182	13	-184
6	6	-84	6	-109	14	-131	13	-149	14	-167	22	-168
7	7	-81	14	-108	18	-130	20	-146	22	-161	14	-167
8	8	-80	15	-107	12	-126	21	-144	21	-158	25	-166
9	9	-79	16	-106	19	-125	22	-141	13	-157	23	-165
10	10	-74	17	-106	20	-125	23	-138	24	-150	26	-162

6. Impacts of Wind Generation on Frequency Management and Demand for Reserves

The impacts of wind generation on frequency management are considered in four main areas, and are ordered by their speed of response:

- the effect of reduced inertia on the management of contingencies,
- the potential need to procure Sustained Instantaneous Reserve (SIR) to manage exceptional wind speed changes,
- the effect of wind variability and 5-minute unpredictability on normal frequency management,
- the potential ramping requirements that wind generation might add to the system.

6.1. Contingent Events

The main effect of wind generation on the management of contingent events is the reduction of system inertia. In Section 5.1 the effect of wind generation on reducing inertia was analysed, and in Sections 3.1 and 3.2 the physics of managing contingent events was briefly described. This section uses the results from these previous sections and analyses the impact reduced inertia has on the demand for Instantaneous Reserves (IR). Since the procurement of IR is dependent on several complex processes, these are described more fully. This is not the first time the impacts of wind generation on the demand for IR has been analysed in New Zealand, and this work is conducted in light of previous work.

6.1.1. Previous Studies on the Demand for Instantaneous Reserve

There have been three main studies in New Zealand on the demand for IR:

1. *Investigation 5 of the Wind Generation Investigation Project (WGIP), Effect of wind generation on management of frequency excursions (Transpower, 2007b).* This report modelled the loss of Otahuhu B (CCGT) at 340 MW on 25th December 2005 at 4.30 am, the lowest demand trading period over the analysis period, being the worst-case scenario with the least inertia. North Island demand was 1679 MW and an extra 230 MW was being transferred to the South Island across the HVDC link. The power system was modeled using the Reserve Management Tool (RMT), which would have been under version 1.0 specification, with a limited HVDC model, not modelling the full benefits of being connected to the South Island. There were four different scenarios of wind penetration, each had a wind generation capacity of 794 MW. Each scenario was differentiated by how much instantaneous wind generation was present and by how many Huntly Rankine units were removed: scenario 1 was the base case scenario with the historical wind generation of 53 MW, scenario 2 increased wind generation to 189 MW with one Huntly Rankine unit was removed, scenario 3 two Huntly Rankine units were removed (329 MW), and scenario 4 three units (469 MW). The results showed an increased requirement for FIR with the base case starting at just under 200 MW, and for scenario 4 the requirement had increased to just over 250 MW. There were other simulations, such as a higher load scenario for the North Island and a brief consideration of the South Island; however, the results did not show the same increase in FIR required.

2. *The System Impacts and Costs of Integrating Wind Power in New Zealand (Imperial College London, 2008).* This report tries to quantify the indirect costs of wind generation on the power system. These costs were considered to come primarily from three sources: the additional generation capacity required to manage wind generation uncertainty, required transmission

capacity, and extra operating reserves. However, the report only considers the capacity adequacy problem and operating reserve requirements. The report anticipated costs for three future scenarios: 313 MW of wind capacity by 2010, 1745 MW by 2020, and 3090 MW by 2030. It estimated that the demand for IR by the 2030 scenario would increase by 184 MW on average and by 378 MW at maximum, which is a significant increase. However, the analysis makes an inadequate assumption in its estimation of the reserve requirement. It assumes that the demand for reserve is determined by the variability in power output of wind generation in the several minutes time window; although this is a correct assumption when considering reserve for Frequency Keeping (FK), it is inadequate for IR as the demand for reserves is dominated by the largest contingent risk.

3. *Technical Advisory Service Contract (TASC) 33, Analysis of Reduced Inertia upon New Zealand Power System (Transpower, 2014b).* The report has the greatest accuracy and significance out of the three studies, and is specifically focused on the impacts of reduced inertia upon the Rate of Change of Frequency (RoCoF) and the minimum frequency reached for a contingency. It considers demand for FIR under three snapshots of the grid: winter peak, summer peak, and summer trough. For each snapshot, the largest Contingent Event (CE) was a CCGT operating at 396 MW, 235 MW, and 170 MW respectively for each snapshot. For each snapshot, one thermal or geothermal unit is removed from the base case scenario at a time, and the grid frequency is simulated. The power system was modelled by PowerTech's Transient Security Assessment Tool (TSAT). Utilizing the transaction analysis capability tool, the demand for FIR was calculated. The results showed for the winter peak, if 932 MW of thermal generation was removed and replaced by wind generation, then an extra 125 MW of FIR is required. For the summer peak, if 366 MW of thermal generation is replaced then an extra 20 MW is required, and for the summer trough, with 416 MW removed, an extra 51 MW is required. These results show the clear implication of reduced inertia on the requirement for FIR.

The current research cannot replicate the results of TASC 33, due to proprietary restrictions; however, it models the main features of the power system, and captures the general shift in requirements for FIR and SIR. TASC 33 provides excellent analysis, so this research mainly focusses on the relative change.

6.1.2. The Factors Influencing Demand for Instantaneous Reserve

The demand for IR is dependent upon four factors:

1. *The level of risk to be covered.* The level of risk is defined by the distinction between Contingent Event (CE) and Extended Contingent Event (ECE) as formally stated in Transpower's Policy Statement (Transpower, 2017a), and reviewed every five years by the credible event review (Transpower, 2014a). A CE is an event that is expected to occur more often than once every five years and has to be covered by IR without any loss of uncontracted load, where an ECE is expected to occur less regularly, and is allowed to activate the AUFLS system. Events that are considered a CE are the loss of a single generator, a transmission circuit, a HVDC pole, and the loss of reactive injection. For ECE, events include the loss of the HVDC bipole, loss of a 220 kV interconnecting transformer, and the loss of a 110 kV or 220 kV busbar; the precise definitions are found in the Policy Statement (Transpower, 2017a). The risk of biggest concern is an HVDC bipole trip, which currently has a transfer capacity of 1200 MW. An HVDC Bipole trip has only happened four times since 2004, two were due to testing the HVDC link's protection and controls in 2013 with the Pole 3 upgrade, a fire close

to the lines in Canterbury tripped them in 2005, and issues with a current transformer tripped both poles in 2015.

In the future, it may be prudent to reclassify a single HVDC pole trip as an ECE, if the reliability of a single pole can be verified, as its reliability has increased with the introduction of Pole 3. However more time is required to demonstrate this reliability. Therefore, this analysis assumes that a HVDC single pole trip will remain a CE for the foreseeable future.

2. *The contribution of AUFLS to covering the risk.* Although AUFLS does not have any influence on IR required for a CE, AUFLS does cover a proportion of the ECE risk, especially an HVDC bipole trip. Therefore, if AUFLS is covering a proportion of the ECE risk, this reduces the demand for IR to cover that risk. Since an ECE does not happen often, it is more economic that AUFLS covers most of the reserve requirements for an ECE event, this is to minimise the demand for IR, and reduce the procurement costs. Currently AUFLS is achieved through two blocks of 16 % demand each, but this will change for the North Island where the scheme will be transitioned to a four block scheme, firstly two blocks of 10 % and then two blocks of 6 %. This is the same total of 32 %, which is a large proportion of the demand, as shown in Figure 6.1. It may not be large enough to cover all of an ECE, especially an HVDC bipole trip above 1000 MW and with other generation tripping at 48 Hz, such as Glenbrook and Te Rapa (Transpower, 2010). However, the current rules around AUFLS (Extended Reserves) allows the block proportions to be reviewed, minimally every five years, and so increase proportion of load in the AUFLS scheme.

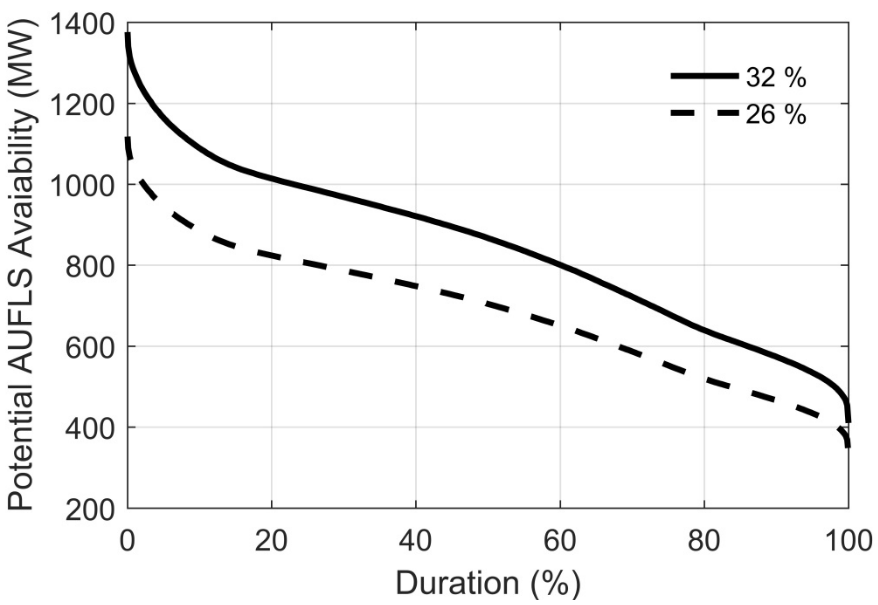

Figure 6.1: Demand duration curve for 32 and 26 % of North Island load. The data is from the start of 2013 to the end of 2016 based from GDX files offered for vSPD by the Electricity Authority. 26 % is the lower limit that should be achieved (Transpower, 2017b).

3. *The system conditions as modeled by the Reserve Management Tool (RMT).* The RMT considers the state of the power system and analyses how much FIR is required. It does this by conducting a time simulation of the power system frequency and iterates through a number of IR options to achieve the least amount of FIR required to keep the frequency above 48 Hz. It is modelled in this simulation how inertia influences the demand for FIR, and therefore captures the primary influence

wind generation has on the procurement of IR. With low inertia, the frequency falls faster than it otherwise would have for a CE, therefore more reserves are procured to increase the speed of response. These relationships have been analysed in Sections 3.1 and 3.2.

4. *Optimization of SPD.* The size of many of the risks is dependent on which generators are running; therefore, the size of the risk can be optimized in the Scheduling, Pricing, and Dispatch (SPD) tool against the availability of reserves. If there is a shortage of reserve then it may be necessary to reduce the size of the largest risk. This process is difficult to model, hence the influence of SPD on limiting the size of the largest risk will not be considered in estimating the demand for IR under higher wind generation penetrations. However, the availability of IR is considered in Section 7.1.1.

6.1.3. Demand for Instantaneous Reserves

There are three main scenarios that are considered in determining the impact of wind generation upon the demand for IR: the loss of the HVDC bipole, the loss of a single HVDC pole, and the loss of the largest generator. Historically there have been other events of concern, such as the sympathetic trip of an HVDC pole with another generator trip, and other multiple generator ECEs. However, since the sympathetic trip of the HVDC link was associated with the commissioning of Pole 3 and other ECEs are not anticipated to be bigger than an HVDC bipole trip, the analysis is limited to these three scenarios.

1. The loss of the HVDC bipole

The loss of the HVDC bipole, in both the North Island and the South Island, has the potential to be the largest event to occur on the grid as more wind capacity is installed, as seen in Figure 6.2 with increasing North transfers across the HVDC link. It could be bigger than the entire loss of Huntly Power Station (950 MW), or a Manapouri busbar fault tripping three units (375 MW). Also for the HVDC bipole trip it separates the power system into two, weakening both islands, not allowing one island to support the other one. Since an HVDC bipole trip occurs infrequently, and therefore is classified as an ECE, AUFLS is the main mechanism by which the power system is kept stable. However, some generation does not remain connected to the power system below 48 Hz, and the amount of AUFLS available may be insufficient, therefore IR is procured to finally ensure sufficient security. Procuring IR has a direct cost, hence AUFLS should cover most of HVDC bipole risk most of the time. Since the process of developing the AUFLS scheme is regularly reviewed, it is assumed the AUFLS scheme will be adjusted to minimise IR demand. However, it is shown that under the current two blocks AUFLS system in the North Island, a review is required. This review has already been completed by Transpower and the Electricity Authority, and a new scheme was to be implemented by 2018. The recommendation is AUFLS should be continually reviewed as HVDC transfers increase.

In the procurement of IR to cover an HVDC bipole risk, the Reserve Management Tool estimates the contribution of AUFLS and the lost generation's contribution to the risk. This contribution is modelled in SPD by the DCECE Net Free Reserves parameter, which means how much of the DC Bipole risk does not have to be covered by IR. In Figure 6.3, the distribution of Net Free Reserves in the North Island for varying total HVDC transfer North to Haywards is plotted. Most of the time there are sufficient Net Free Reserves to cover the whole HVDC bipole risk, as seen by the blue line having a one to one relationship. This is seen more clearly in Figure 6.4, where an estimate for NI SIR demand due to a DCECE is plotted against HVDC transfer. At approximately 700 MW there are usually sufficient free reserves. However, by 500 MW transferred North there are situations where there is minimal Net Free Reserve and the demand for IR has increased to 400 MW, close to the risk size of an CCGT. By 850 MW transferred North, it is expected that there is some IR requirement.

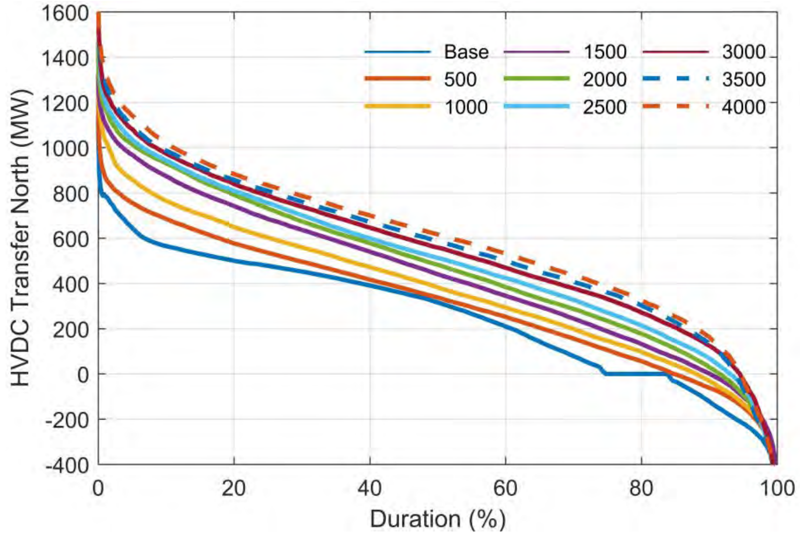

Figure 6.2: Duration curves of HVDC transfer north from simulations of redispatching thermal and hydro generation under greater installed wind generation capacities. The results from this figure are for 2013. The historical base case is compared against each wind capacity scenario from 500 MW to 4000 MW.

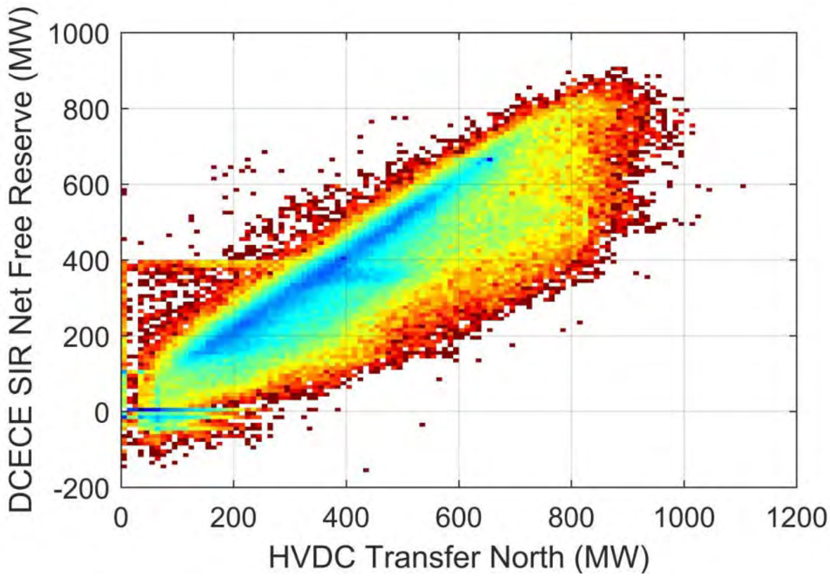

Figure 6.3: Distribution of HVDC Transfer compared against DCECE SIR Net Free Reserve. The bluer the color shows greater likelihood. The data was taken from GDX files of vSPD model of the electricity market, from May 2004 to June 2017.

Figure 6.2 shows that with increasing wind penetrations, where new installed South Island wind generation needs to bring its energy to the North Island, that HVDC transfers would increase. With 1500 MW of new installed wind capacity approximately 15 % of the time HVDC transfer is greater than 800 MW, which start to regularly influence the demand for IR. Therefore, it is at least necessary to review, after the new Extended Reserves scheme has been implemented, whether there is sufficient AUFLS available to prevent excessive demand for IR.

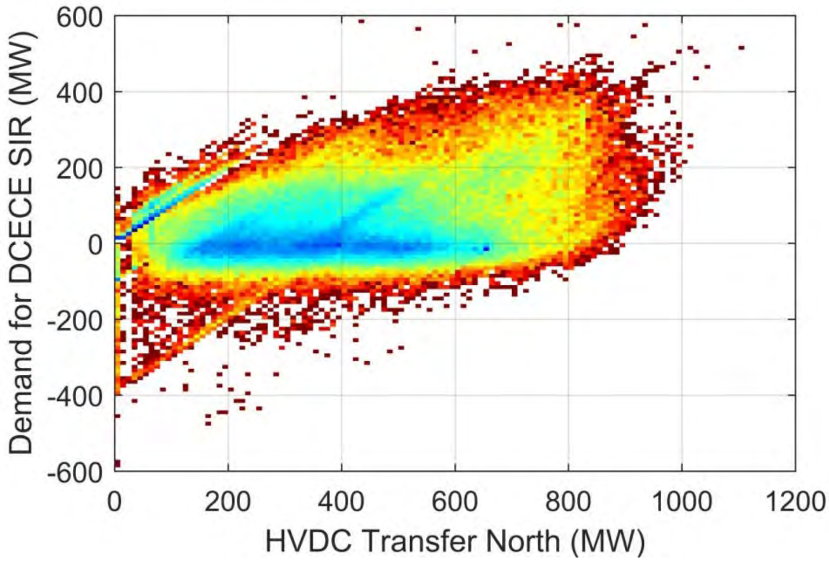

Figure 6.4: Distribution of HVDC Transfer compared against DCECE SIR demand. The bluer the color shows greater likelihood. The data was taken from GDX files of vSPD model of the electricity market, from May 2004 to June 2017.

2. The loss of an HVDC pole

AUFLS is not used as the main mechanism to keep the power system stable for HVDC single pole trip. Unlike the HVDC bipole trip, a single pole trip is considered a CE as it occurs more frequently. However, one pole can ramp up if the other is tripped, sharing the demand for IR with both Islands. This section analyses the changing demand for FIR and SIR to cover the risk of losing an HVDC pole as installed penetrations of wind generation increase. This is completed by modelling the changes in HVDC transfer, through the use of the re-dispatch model, and then using the power system dynamic model described in Eq. 3.5.

In Figure 6.2 the results of simulating HVDC transfers under new installed wind generation is shown. The simulation did not limit HVDC transfer to 1200 MW, but is unlikely that transfer will go above this limit, so for the purposes of calculating DCCE risk, maximum transfer is capped at 1,200 MW. The risk is calculated by subtracting ramp up capability of 650 MW from the total transfer, Figure 6.5 and 6.6; this is in accordance with the SPD formulation. Note that the size of risk is the required amount of SIR. DCCE risk for the South Island, although not absolutely zero in every scenario, is inconsequential, and is not further considered.

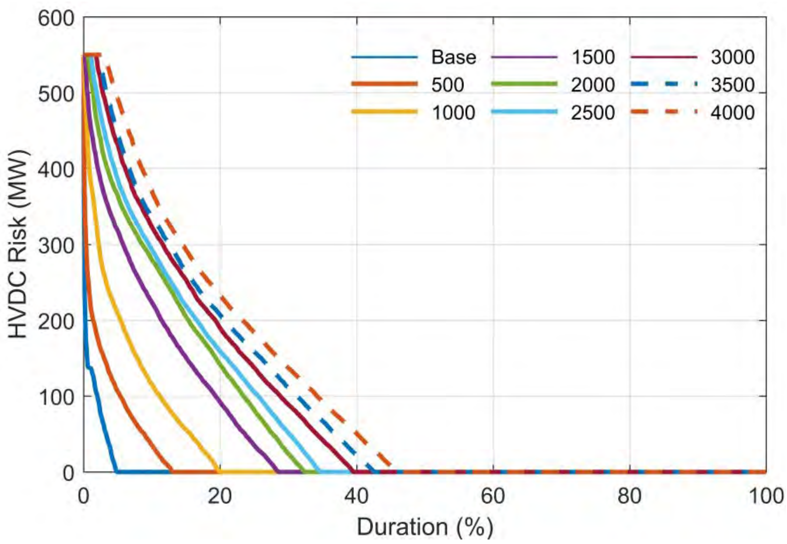

Figure 6.5: Duration curves for DCCE risk in the North Island for the different wind generation scenarios, 2013.

The increase in DCCE risk greatly increases the SIR requirement such that the level is comparable to that of the CCGT by the time there is 1000 MW of new installed wind capacity. The situation is comparably worse as there is no ability to share inertia and reserves from the South Island as the HVDC has no further capacity. The requirement for FIR in the North Island is calculated by applying the model in Eq. 3.5 and solving for the required response time, τ_r, of reserve to ensure that the frequency does not fall below 48 Hz. The demand for FIR is calculated from:

$$FIR_{MW} = (\tau_{FIR} - \tau_d)\frac{\Delta P}{\tau_r} \tag{6.1}$$

where FIR_{MW} is the demand for FIR in MW, τ_{FIR} is 6 seconds as per the definition of FIR, τ_d is the time delay of first response of 1 second, and ΔP is the size of the risk. Before τ_r can be solved, τ_m is estimated by Eqs. 3.4 and 3.9. The distribution of τ_m is presented in Figures 6.6 and 6.7, and the resultant changes in demand for FIR is shown Figures 6.8 and 6.9 after solving for τ_r.

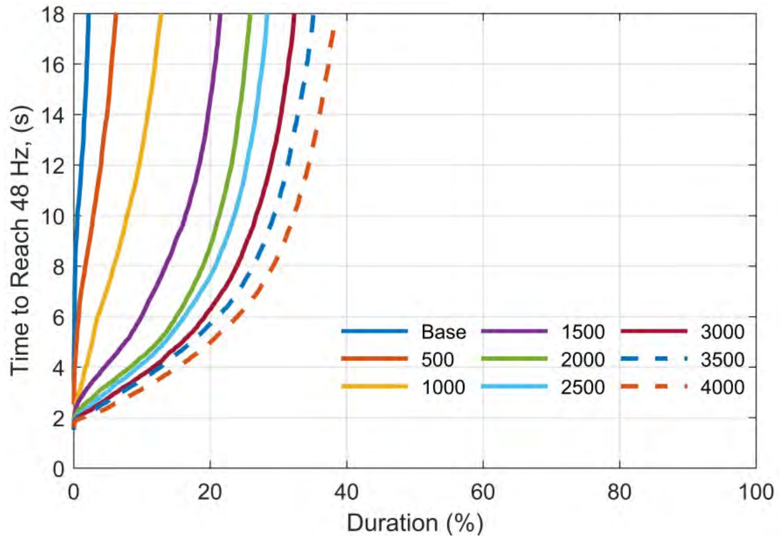

Figure 6.6: Duration curves for the estimated time to reach 48 Hz unaided by the natural response of loads or of reserve. This figure is for the simulation results of 2013. For most of the time the other pole can cover the loss, and the risk is zero.

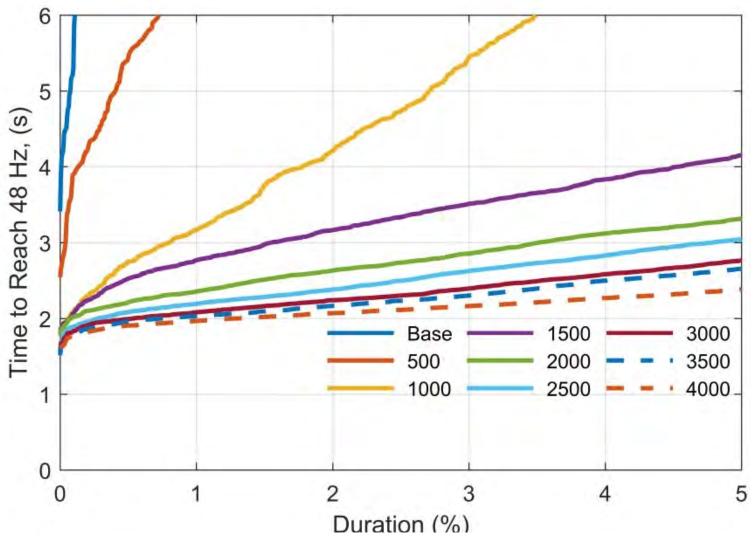

Figure 6.7: Detailed view of Figure 5.6 above.

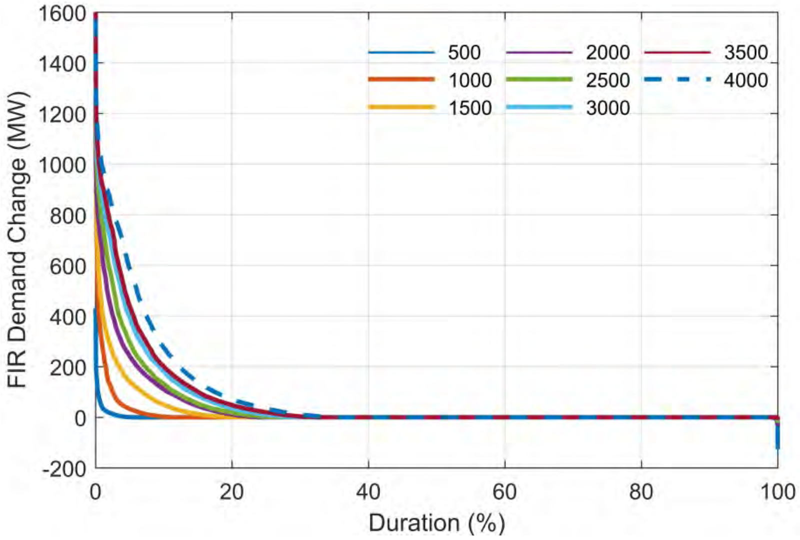

Figure 6.8: Duration curves for changes in FIR demand from the base case scenario for different installed wind scenarios. These results are for 2013. Results for 2014 and 2015 can be found in Appendix G.

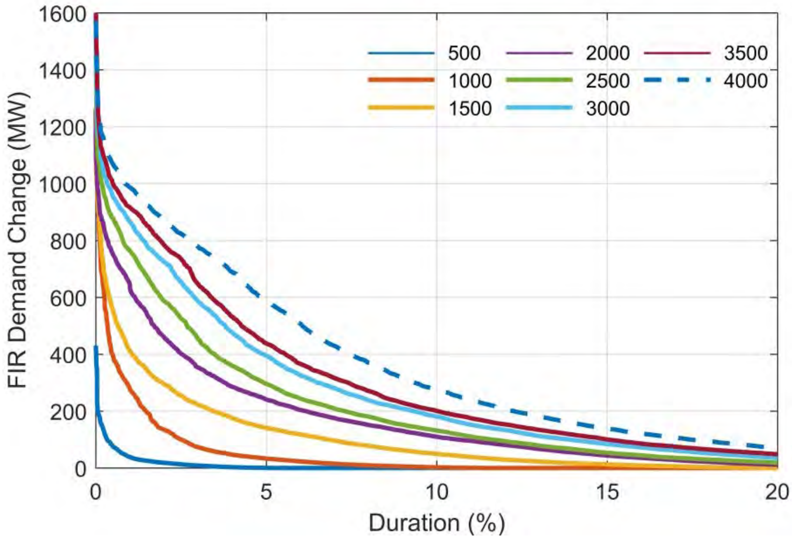

Figure 6.9: Duration curves for changes in FIR demand from the base case scenario for different installed wind scenarios. These results are for 2013. Results for 2014 and 2015 can be found in Appendix G.

As the installed wind generation increases, there are more periods where South Island wind generation is supplementing North Island generation with low winds in the North Island. This causes higher transfers across the HVDC link coupled with lower than usual inertia in the North Island. The frequency can fall to 48 Hz very quickly without any response from reserves. From Figure 6.7, some scenarios have instances where it would only take 1.6 seconds. This will create large demands for FIR as seen in Figure 6.9, were the demand for FIR can increase to 800 MW for an extra installed wind capacity of 1500 MW. Although this is a large FIR demand, the calculation of the FIR requirement assumes only reserve from Partially Loaded and Tail Water Depressed spinning reserve is offered, as implied by Eq. 6.1. However, if Interruptible Load (IL) which reacts more quickly than spinning reserve is a part of the mix then the demand for FIR will reduce, as the value of 1 MW of IL is higher than 1 MW of spinning reserve. The value of IL compared to spinning reserve is analysed in Appendix A.

It is noticed that the requirement for FIR can be significantly larger than the requirement for SIR, and is shown in scatter plots of Figure 6.10 for the historical, 2000 MW, and 4000 MW new installed wind capacity scenarios. From SIR requirement of greater than 400 MW, FIR requirement increases at a greater rate. Therefore, it is likely that the FIR reserve market will be the constraining market in these circumstances. When this occurs, there is possibility it will coincide with peak electricity demand, and high electricity prices. This will force Interruptible Load providers offering FIR to reconsider their load size and possibly remove that load from the energy market and the IR market. The removal of IL has to be satisfied by spinning reserve, which theoretically requires more capacity than IL, as it is slower to respond. This constrains the power system even more as more generation capacity is removed from providing energy. In practice, the added benefit of IL over spinning reserve cannot be accounted for as SPD considers one MW of IL equivalent to one MW of PLSR or TWDR.

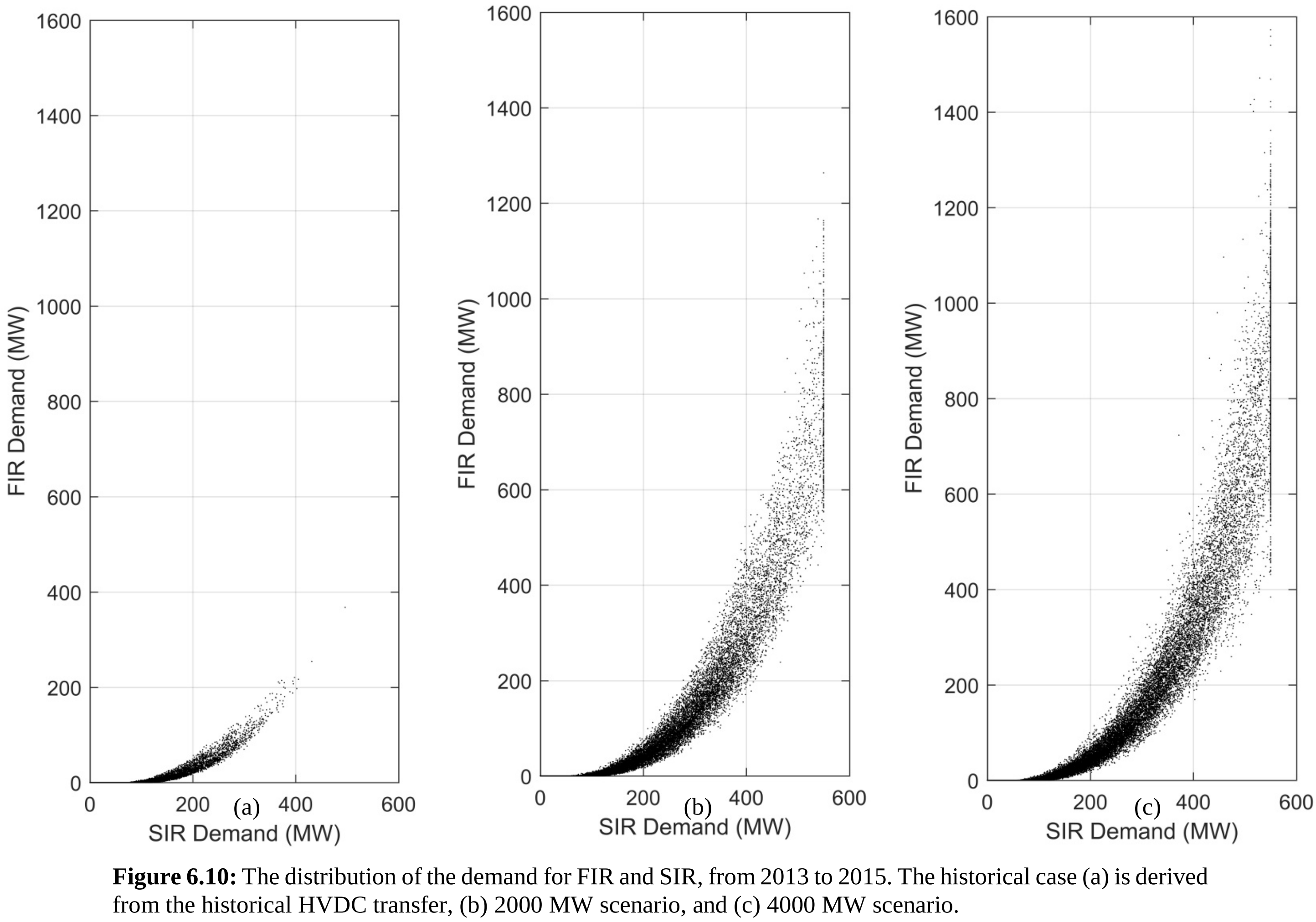

Figure 6.10: The distribution of the demand for FIR and SIR, from 2013 to 2015. The historical case (a) is derived from the historical HVDC transfer, (b) 2000 MW scenario, and (c) 4000 MW scenario.

3. The loss of the largest generator

The loss of a single generator is the dominant risk in each island that requires IR. This section analyses the impact that increasing wind capacity has on the IR required to cover this risk. There are two main impacts that wind generation has on changing the demand for IR in this situation: the reduction in inertia, which reduces the amount of Net Free Reserve that is available; and the reduction in the size of the largest risk, as wind generation removes the largest thermal units from the market. The modelling assumes that both the North and South Island are a single synchronous network, enabled through the use of HVDC link and associated frequency controls. This cannot be entirely justified as there are periods where the HVDC link is not in operation; however, these are during periods when the risk is low.

The results of modelling how extra wind generation impacts the dispatch of thermal and hydro generation, Appendix C, are used to analyse changes in the largest risk generators. The largest risk can be from the following units, Otahuhu CCGT, Southdown CCGT units, Huntly U1 to U4, Huntly CCGT, Nga Awa Purua, Stratford CCGT, Stratford OCGT, and finally it is assumed that there is at least one Manapouri Unit running at 125 MW. Note the risk is not separated by island, as the power system is modelled as one synchronous network. Figure 6.11 shows the changing level of risk as wind capacity increases. The largest risk also shows the demand for SIR, which declines steadily until the power system is saturated with wind generation. Figure 6.11 particularly shows results for 2013, results for 2014 and 2015 are in Appendix E.

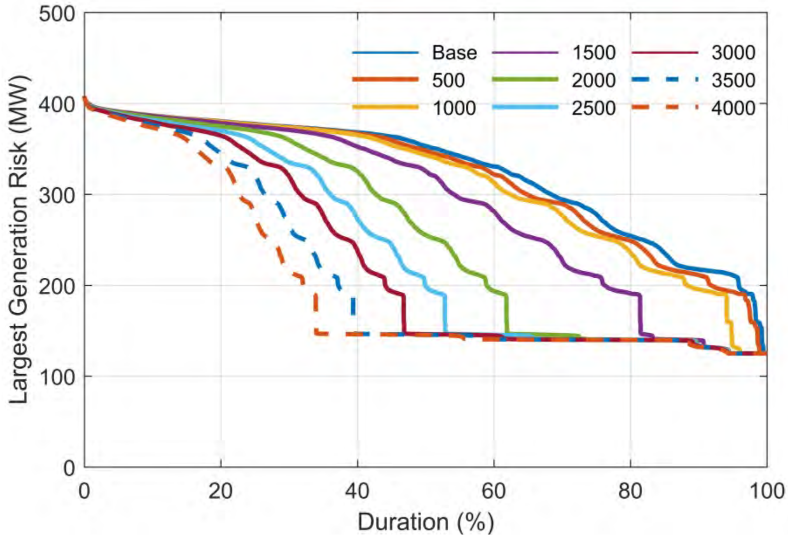

Figure 6.11: Simulation results of finding the largest generator risk for 2013. This plot shows the duration of time that the power system is above a level of risk. The base case, is the historical profile.

To understand how reduced inertia and changes in risk affect the required amount of FIR, an intermediary step of calculating the time the system takes to reach 48 Hz unaided, τ_m, is calculated from Eq. 3.4 and 3.9. For 2013, the results are shown in Figure 6.12, and more closely in Figure 6.13. Generally, the reduced inertia decreases the time it takes to reach 48 Hz, as expected and seen in the case of an added 500 and 1000 MW of wind capacity. Once the size of the largest risk starts to decrease, i.e. for scenarios increasing from 1500 MW to 3000 MW of new installed wind generation, τ_m increases quite significantly. Focusing on the smallest τ_m in Figure 6.13, the reduction in inertia has a clear impact on τ_m, where the minimum τ_m for the base case is 4 seconds and decreases to 3 seconds by the third scenario. The required installed wind capacity to reach 3 seconds depends largely on the year, as both 2014 and 2015 show different scenarios for which a τ_m of 3 seconds is reached, and depends on the hydrology for each year.

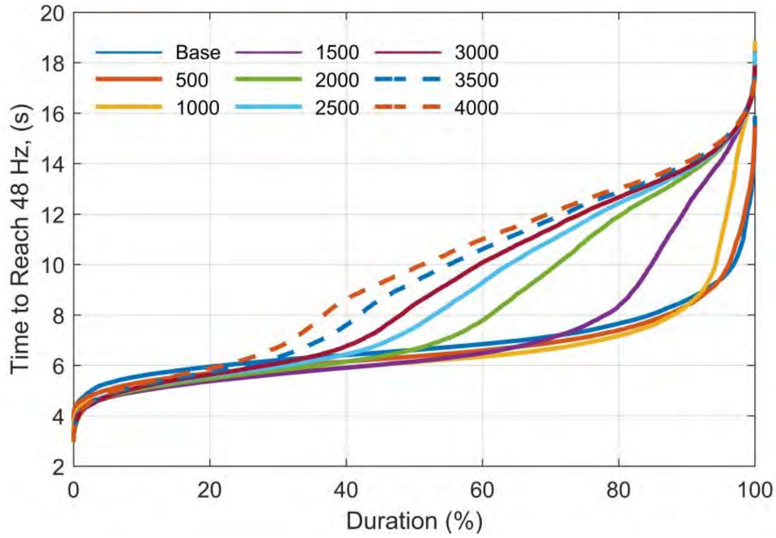

Figure 6.12: Simulation results of determining the time for the frequency to reach 48 Hz unaided for 2013. This plot shows the duration of time that τ_m is below. Corresponding results for 2014 and 2015 can be found in Appendix E.

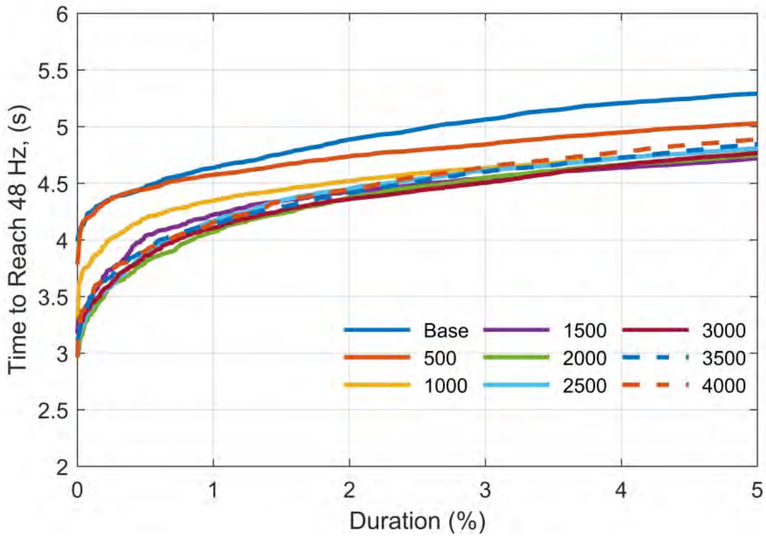

Figure 6.13: Detailed view of Figure 5.12. Corresponding results for 2014 and 2015 can be found in Appendix E.

Determining the demand for FIR follows the same approach as for the loss of an HVDC pole, i.e. through calculating the required response time to keep the frequency above 48 Hz, and then applying Eq. 5.1 to estimate FIR requirement, Figures 6.14 and 6.15. For most of the time from the 500 MW to 1500 MW scenarios, the demand for FIR slightly increases as the inertia reduces, until the reduction in the largest risk significantly reduces the demand for FIR. There are also periods at low inertia when FIR demand is significantly greater. However, this is not expected to surpass the requirement for SIR, as shown in Figure 6.16, as the requirement for FIR is always substantially less than the requirement for SIR. Since SIR will remain the constraining factor in the electricity market, it is expected that the influence of wind generation in reducing inertia will not impact the reserve requirement for the largest ACCE risk, but rather the influence of wind generation in minimising how often CCGT run will reduce the demand for IR.

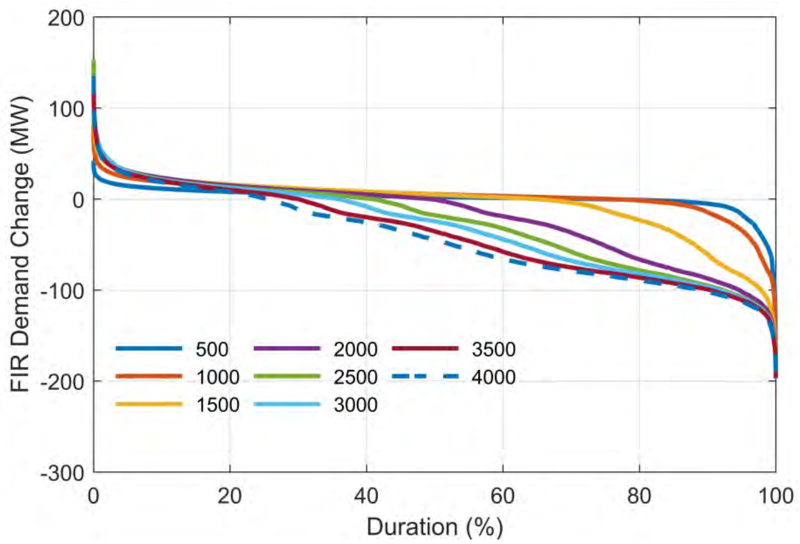

Figure 6.14: Duration curves of the change in demand of FIR from the historical FIR requirement. The results are for 2013.

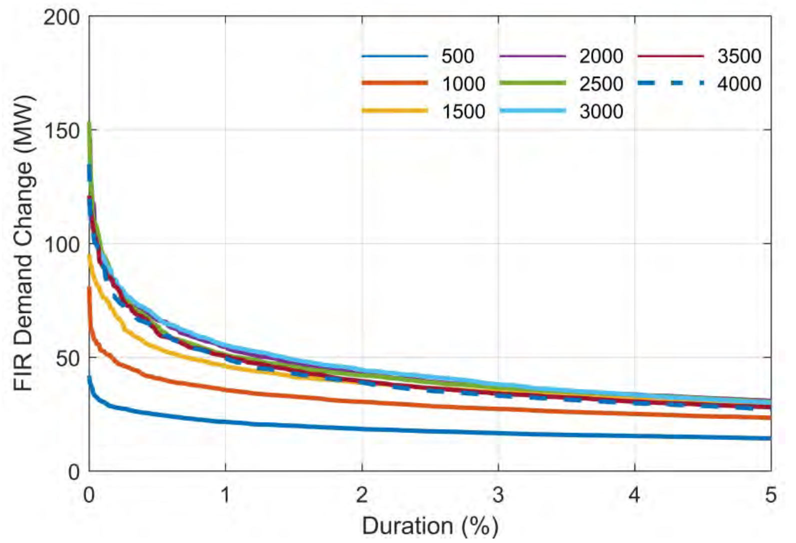

Figure 6.15: Detailed view of Figure 5.14.

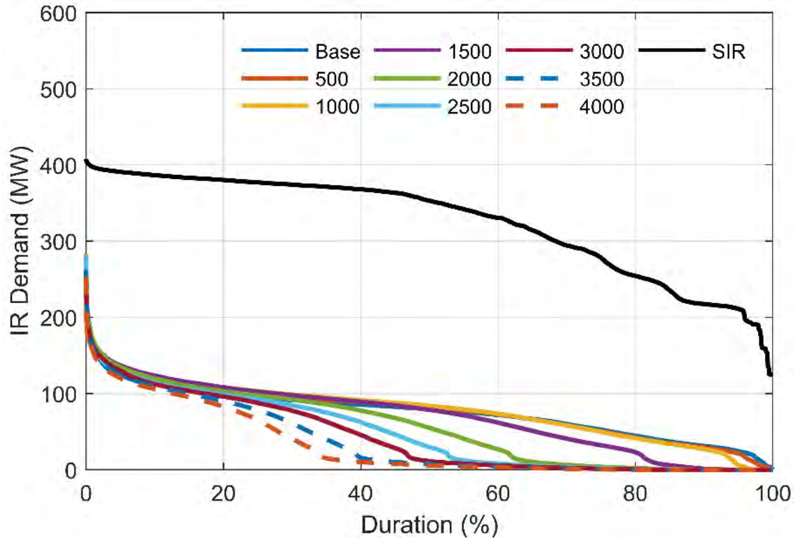

Figure 6.16: Duration curves comparing the absolute demand for FIR against the historical demand for SIR. This is for 2013.

Determining the largest risk on the power system assumed that any new generation would be smaller than the set of thermal risks or Manapouri. Individual wind turbines in New Zealand are 3 MW at most, and bigger turbines are below 10 MW, they will not contribute individually to the risk. However, a wind farm can be lost through a single transmission failure and require the procurement of reserve to manage the event. Currently the largest this risk can be is 116 MW, if one of the West Wind's connections to the grid is lost, while the other connection is out of service. Since there is usually at least one other generation unit greater than this, a wind farm is never set as a risk setter, and there has been no event where the loss of a wind farm has caused the frequency to go below 49.5 Hz. However, if larger windfarms in New Zealand are built then they will be added to the list of potential risk setters, and with the likelihood that demand for IR will decrease, wind farms could lead to an increased demand for IR. An event like that of the 2016 South Australian Black-out is considered an 'Other Event' in New Zealand. These events utilize the AUFLS scheme, hence it is difficult to predict the required IR to manage these events.

6.2. Wind Generation Events

This section is concerned with the impacts of large changes in wind generation power output over a short amount of time, such as the anticipated maximum change in 5 minutes of 200 MW, caused by either a sudden drop in wind speed, or a sudden increase in wind speed causing the wind turbine to shut down on over speed.

A ramp rate of 200 MW in 5 minutes, 40 MW/min, is not a concern in itself, in terms of the dynamics of the power system. This has been demonstrated by the power system response to events where a 400 MW CCGT is lost instantly without system collapse. Also, Investigation Five of the WGIP, analysing these sorts of events, noticed little impacts on frequency deviations at generation ramps of 50 MW/min and higher. However, as discussed in the previous section on demand for IR, there may be periods where the amount of SIR procured is less than a 200 MW. This is because there is a general decline in demand for IR to cover generator risk, except for brief periods of increased demand to cover an HVDC single pole risk. The overall result is that there will be periods where the total risk is not greater than 140 MW (from the Nga Awa Purua power station, or even a 125 MW Manapouri unit). Therefore, it may be necessary for wind fluctuations to be the risk setter in the SIR market during significant weather events. The System Operator may feel that updating the dispatch earlier than the regular five minutes is sufficient for managing these events.

6.3. Normal Grid Conditions

Normal grid conditions relate to continuous and real-time operation of the grid, including free governor action (droop response) and Frequency Keeping (FK). This section estimates the likely impacts of increased wind capacity upon requirements for governor action, and an estimate of Frequency Keeping demand changes is estimated from load and wind generation variability over 5 minutes.

6.3.1. Variability

Load and wind variability has direct implications on how much work is required by controlled generation to balance out this variability. Depending on how closely the grid frequency is maintained at 50 Hz, the amount of effort required in adjusting control surfaces is proportional to the variability. In the worst-case scenario, where the grid frequency has to be kept at exactly 50 Hz, the amount of effort is exactly equal to the up and down movement in the variability. This situation is at an unachievable limit, as it requires perfect foresight of the imbalance. Since perfect foresight is unavailable, control systems measure grid frequency and respond accordingly, as explained in Section 3.3. A practical control structure implies a certain range of oscillation periods in the variability would produce a greater response from controlled generation than required. This is seen in the spectral plots of Figure 3.7, where there is a small range of oscillation periods that have a greater magnitude than the natural inertia response of the system would give. To properly estimate the control effort would require a well-developed model of the power system, but to simplify the analysis, an approximation is made by assuming the effort done by controlled generation is equal to the variability of load and uncontrolled generation. Therefore, the results from this analysis should only be taken as a relative measure between the different wind generation scenarios, and not the actual work done in adjusting power output to match the variability in absolute terms.

In this work variability is defined as the standard deviation of a power error signal, either for load, wind generation or both of them together. The error signal is derived by the difference between the original power time series and a low pass filtered version of the same. The cut off frequency is 1.7 mHz, which corresponds to an oscillation period of 10 minutes. This filtering effectively separates the sub 5-minute variations in the signal from the errors in the dispatch process. Therefore, this section does not consider work done in correcting dispatch errors, which is left to the section on the demand for FK.

To understand the impact of wind generation on power variability, it is important to know how wind power variability compares to load variability. Load variability in New Zealand is dominated by industrial processes in the North Island, particularly in the steel making processes in the upper North Island. This is shown in Figure 6.17, where North Island load variability is more than twice that of the South Island, and the total New Zealand Variability is dominated by the North Island. From Figure 6.17, it is noticed that North island variability decreases during the summer holiday periods, likely due to a decrease in industrial work, and there is a step reduction in variability in October 2015 which is due to the closure of an electric arc furnace in Auckland.

Current installed wind generation has a variability that is less than load, as shown in Figure 6.18. The independence in variability between load and wind gives a total variability that is only slightly greater than load by itself. For future scenarios of increasing wind generation, the total variability increases. This analysis applies the estimates made in Section 5.3 to scale the current wind variability time series, and compared against the load variability. The results are shown in Figure 6.19. The trend in increasing variability is shown in Figure 6.20, for the current situation after the closing of the Electric Arc Furnace (EAF), the variability is expected to increase to 42% above the current level of variability with an extra installed capacity of 4,000 MW. However, this is not significantly greater than historical variability before the 1st October 2015.

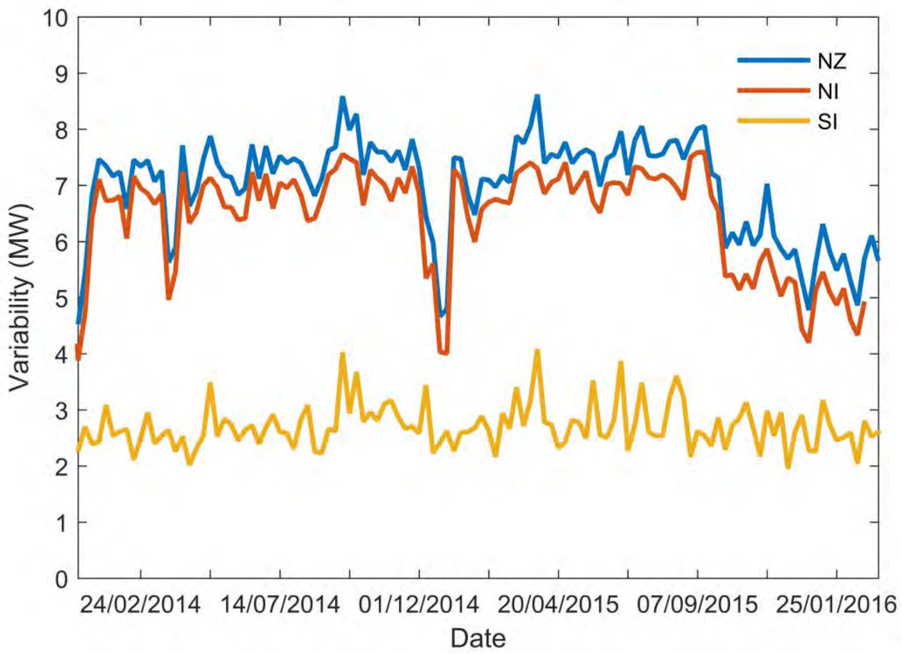

Figure 6.17: Weekly demand variability.

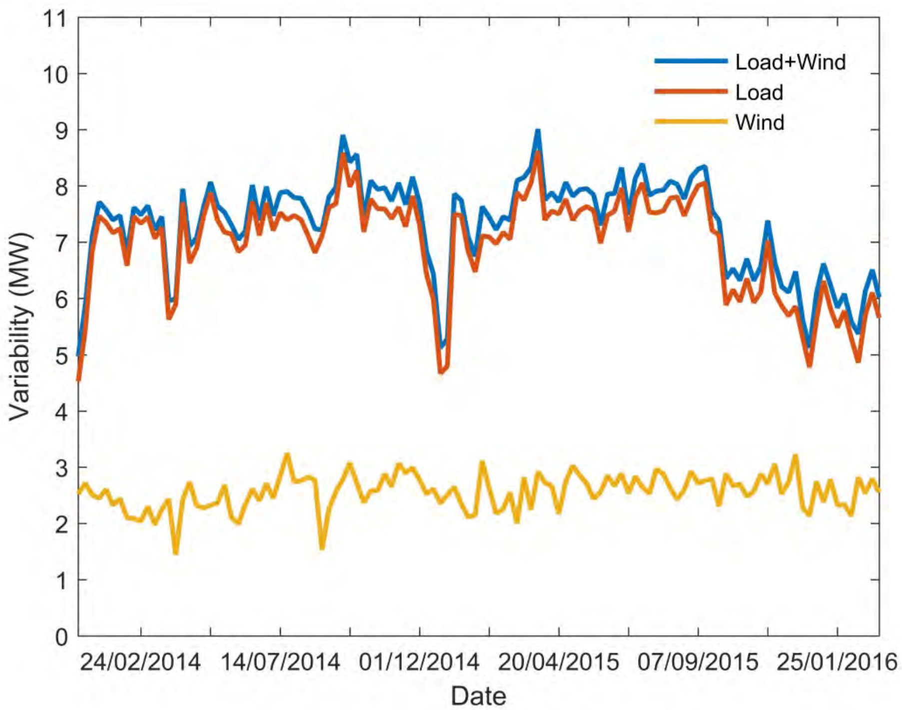

Figure 6.18: New Zealand weekly variability, including demand, wind, and the total from these two sources.

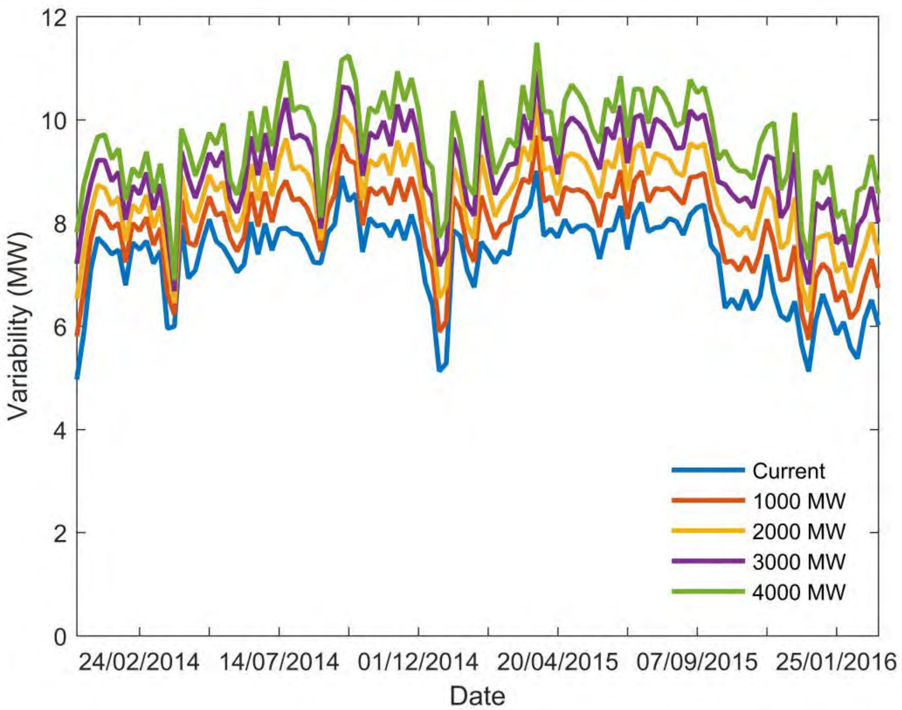

Figure 6.19: New Zealand weekly variability of demand and wind generation, for the different scenarios of increasing wind generation.

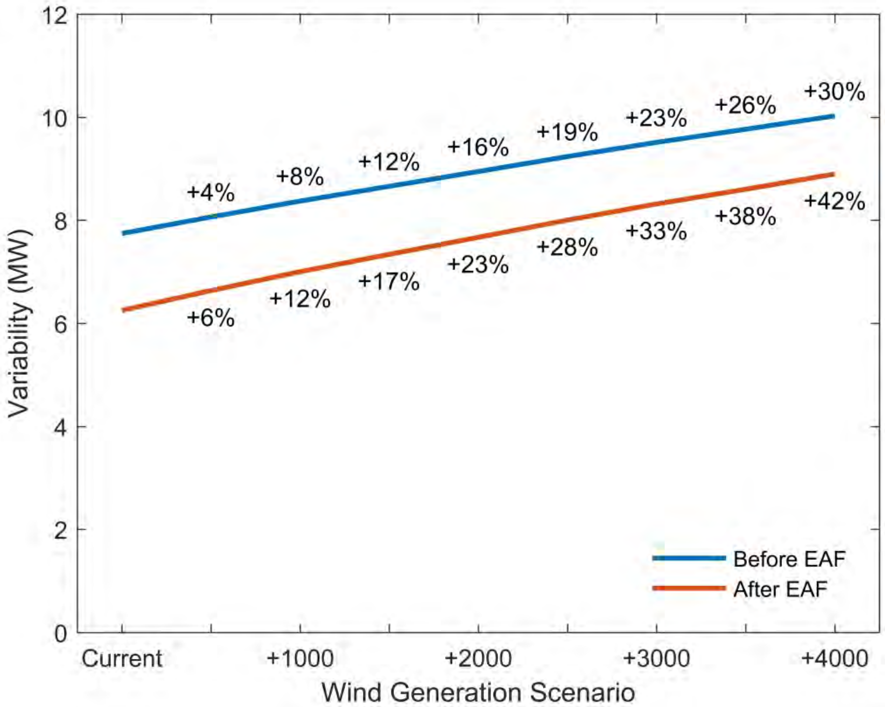

Figure 6.20: Trend in total New Zealand load and wind variability, as the total installed wind capacity increases in each scenario. The legend refers to two historical time periods for which the variability is calculated: the first period is one year ending on the 1st October 2015, when the Electric Arc Furnace (EAF) closed, the second period is for half a year beginning on the 1st October 2015.

6.3.2. Frequency Keeping Requirement

Determining the need for FK is not as easy as it is for IR. For IR the demand is determined by the RMT based on the largest risk on the power system. FK keeps the frequency close to 50 Hz, for a given deviation between the dispatch and current demand. However, there is no precise standard on how well FK is to keep the grid frequency close to 50 Hz, and no model to predict how much FK capacity is required for an expected distribution of dispatch error. The amount of FK procured is based on experience, obtained through test periods when different quantities FK are procured. Secondly, analysis can be completed in hindsight to check the utilization of the Frequency Keeper's capacity. In this analysis the amount of FK required under higher penetrations of wind generation is estimated from the distribution of changes in wind generation after five minutes.

Before estimating the demand for FK based on changes in wind generation over five minutes, the current load and wind changes over five minutes are compared against the current 30 MW of FK. Load changes follow a more predictable pattern than wind changes. To remove the predictable component in the demand time series, the slow changes in demand are removed by a low pass filtered version of the same signal, retaining fast changes. The cutoff frequency of the low pass filter is 0.27 mHz or a period of oscillation of one hour to retain the unpredictable component of the time series. The standard deviation of changes in load over 5 minutes is 16.6 MW, or if the predictable component is included, i.e. the original signal, the standard deviation is 27.2 MW. The 5-minute wind generation unpredictability is 8.9 MW, when summed with unpredictable load variability of 16.6 MW results in a total unpredictable variability of 18.8 MW, therefore 30 MW of FK covers approximately 1.6 standard deviations of the unpredictable variation. In estimating the demand for FK, under higher penetrations, a conservative estimate is made that two standard deviations are to be covered.

In Section 5.4 an estimate of 5-minute unpredictable variation is made in Figure 5.18 for higher penetrations of wind generation. The prediction is $\sigma = 0.186Cp^{0.593}$, where σ is the standard deviation of the 5-minute differences in wind generation, and Cp is the capacity of wind generation. The required capacity for FK to cover two standard deviations of the total load and wind changes is shown in Figure 5.21. The requirement for FK does not exceed 70 MW, even with 4,000 MW of extra wind generation.

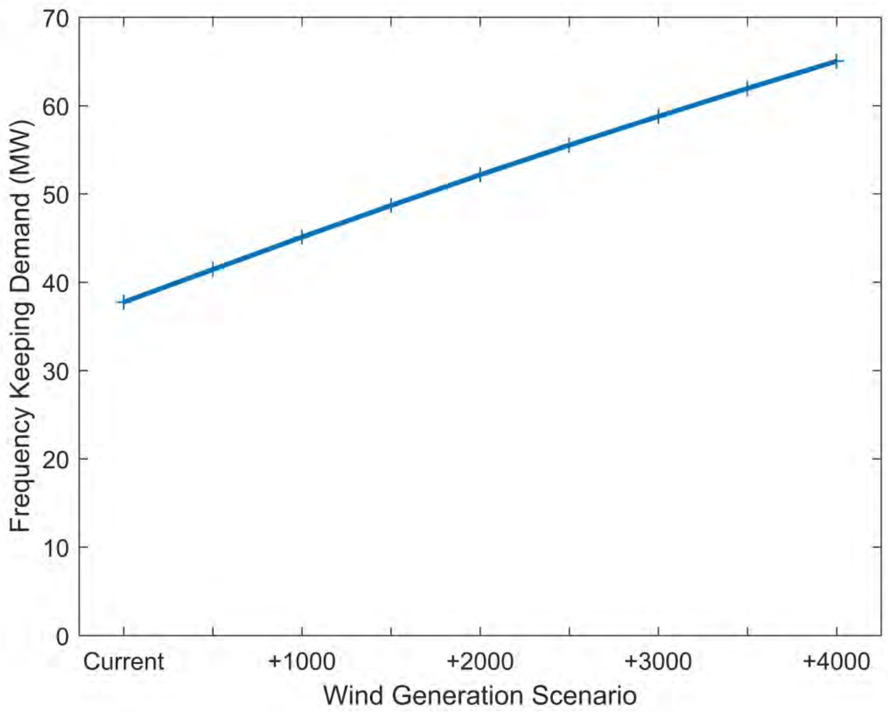

Figure 6.21: Estimate of demand for FK under high penetrations of wind generation.

6.4. Ramping Requirements

Ramping rates are primarily a concern for countries that are dominated by thermal generation. Ireland has defined a new Ancillary Service called Ramping Margin to ensure enough generation is available to follow load and wind changes. New Zealand with its abundance of hydro generation has a large amount of ramping ability. To show this ability, the total amount of generation that can come online in 5 minutes is 5,052 MW, assuming that all generation is available with sufficient headroom. After 30 minutes 7,113 MW can come online and by 1 hour 7,670 MW. These results are obtained from Table 3.3. New Zealand's maximum demand is under 7,000 MW and it requires four hours to ramp up to this amount, i.e. the approximate time to ramp up for the morning peak, there should be no difficulty in satisfying ramp constraints. The more important issue is ensuring sufficient generation to satisfy the energy and reserve demand. These situations have happened in the past and are analysed in Section 7.2.

7. Reserves Availability

This section analyses the availability of reserves by considering what has been offered into the reserves market in the past, and considering several events where there has been a shortage of reserves. This provides a perspective on issues that may occur in the future under higher penetrations of wind generation. Reserves that are considered are Instantaneous Reserves (IR) and Frequency Keeping (FK).

7.1. Historical Reserve Offers

The recent upgrade of the HVDC link has reduced the requirement for reserves, but as intermittent generation becomes more prevalent on the grid, the demand for reserves will increase for a proportion of the year. It is important to consider the reserves that have been used in the past, but are not now offered into the market. This set of reserves is likely to be returned to the market and can be an inexpensive source of reserves when they are needed.

7.1.1. Instantaneous Reserves

IR, both spinning reserves and Interruptible Load (IL), were in use before the introduction of the New Zealand electricity market in October 1996 (CAE, 1993). Spinning reserve was procured in a similar manner to before the electricity market, such that a decision is made between whether more spinning reserve should be procured or the largest risk should be reduced, this was done by manual consideration by the system operator. Spinning reserve that was of the tail water depressed variety was limited to 50% of the total provision, because of the limited speed of those systems. Initially spinning reserves were procured to ensure that the frequency drop would be arrested once a large generator had tripped, but later consideration was given for the frequency which the system restored to; however, there was no delineation between reserve products, i.e. Fast Instantaneous Reserve (FIR) and Sustained Instantaneous Reserve (SIR), which is later seen in the electricity market.

Since there is limited data on how reserves were provided prior to the formation of the market, the analysis only includes data since the market has been introduced, and for IL since offers have been allowed to be aggregated over several GXPs in 2004. The analysis firstly considers the historical cost of reserves and the price, followed by the historic demand for IR. Next who provided reserve offers is analysed, and finally the distribution of reserves between providers is analysed.

The cost of IR can vary widely depending on the conditions of the grid, where high costs occur during periods of high demand for IR and little supply, which is seen during 2011 and 2012 when the risk was high. IR costs have been consistently above $20 Million per annum, but this has decreased as the benefits of the National Market for IR (NMIR) is decreasing the demand for IR. The cost of IR is shown for a monthly and yearly basis in Figure 7.1. The spot price is shown in Figure 7.2. The energy price is an order of magnitude greater than the IR price for the North Island, and in the South Island the spot price for IR rarely rises above $1/MWh. This shows that the North Island market is more constrained in reserve capacity, whereas the South Island has a large amount of Hydro Generation well suited to IR.

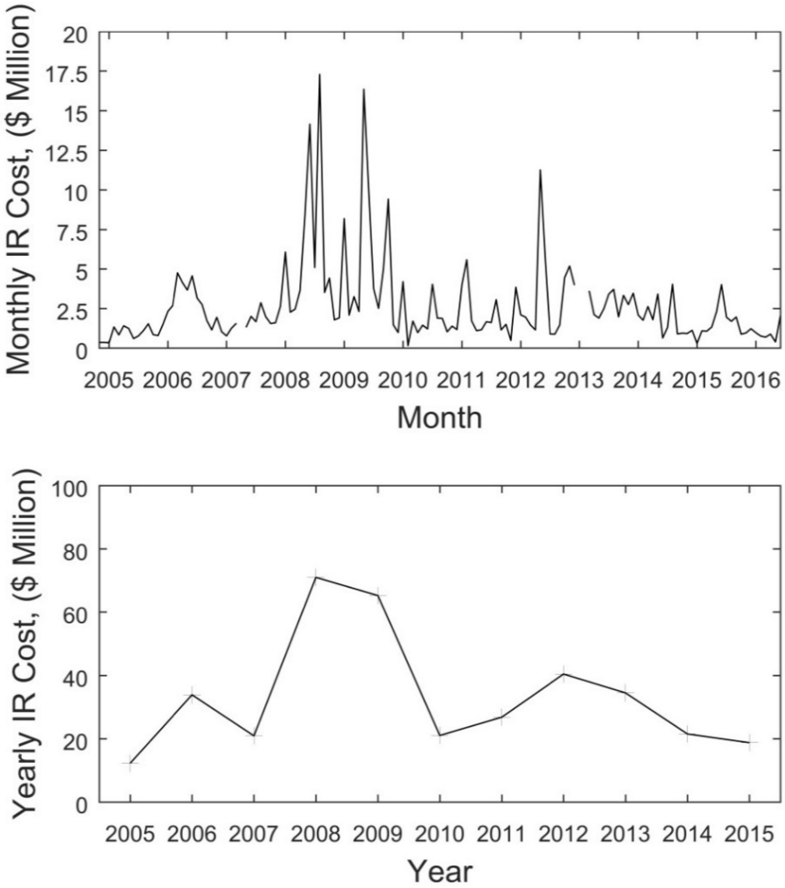

Figure 7.1: Monthly (Top) and Yearly (Bottom) IR costs. (The month of January is on the tick for the monthly plot.) 2007 and 2013 are missing data, so the yearly totals are estimated from the mean.

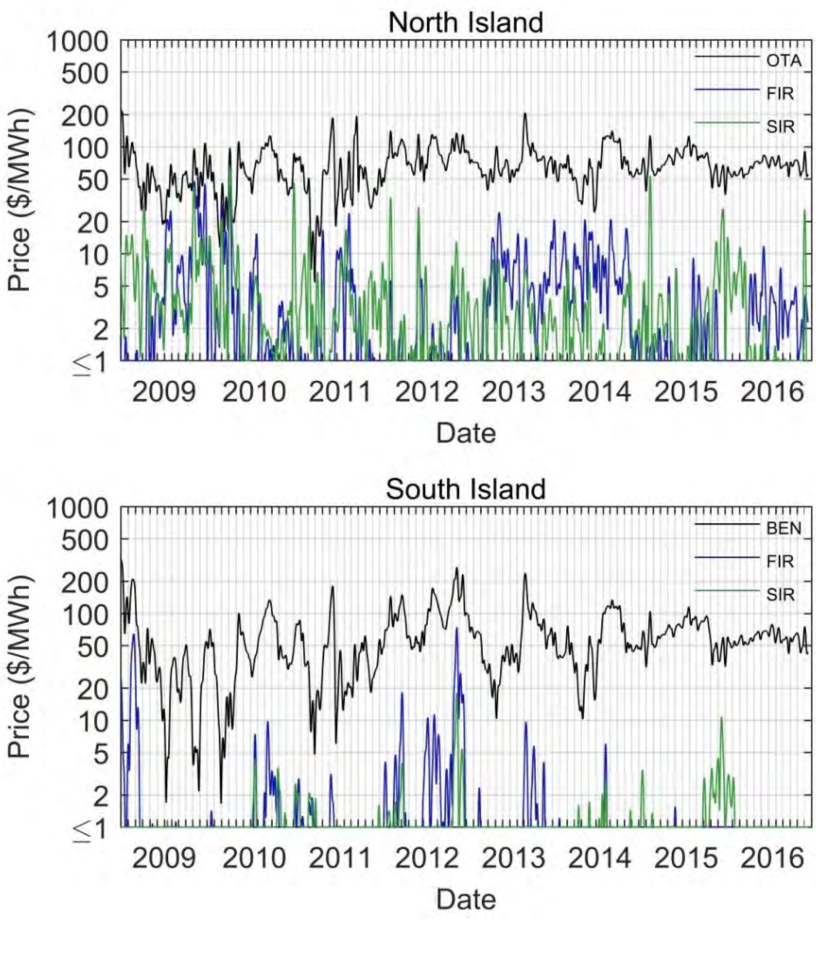

Figure 7.2: Smoothed mean daily energy and reserves price, for both the North Island and the South Island. The dark line is the energy spot price for Otahuhu and Benmore respectively. The blue line is the FIR price, and the green line is the SIR price. The daily mean is taken, then a low pass filter is applied so that variations greater than two weeks can be seen.

Reserve is procured to cover the largest credible contingency, this usually is the loss of the largest generator or the loss of a single pole of the HVDC link less the available capacity on the other pole. Therefore, the demand for SIR in the North Island is the generation output of the largest Combined Cycle Gas Turbine (CCGT), 400 MW, whereas in the South Island it is usually the output of one Manapouri unit, 120 MW. This is seen in the demand for reserve in Figure 7.3. The demand for FIR is less than SIR, due to the natural response of the grid to reduce load when the frequency drops below 50 Hz, but is also influenced by the definition of FIR capacity and speed at which the frequency drops.

From Figure 7.3, there are two features that are worth mentioning: the large demand for FIR and SIR in the South Island for the first two quarters of 2012, and the decrease in SIR in both Islands from the last quarter of 2015. During the early months of 2012 there was a shortage of water in the South Island lakes, driving power flows southward across the HVDC link. At the time Pole 1 or Pole 2 did not have the capability, in south transfer, to carry the power transfer of the other pole if it tripped, e.g. If Pole 1 is exporting 400 MW south and Pole 2 was exporting 400 MW and tripped, then Pole 1 could not increase transfer by 250 MW, and leave an imbalance of 150 MW in the South Island. Hence the largest credible contingent event in the South Island was the tripping of one of the poles, which can be significantly larger than a single Manapouri unit. To compound the problem, the inertia in the South Island was low, as water resources were being conserved. Therefore, a greater amount of FIR was required to cover the contingency (Electricity Authority, 2012).

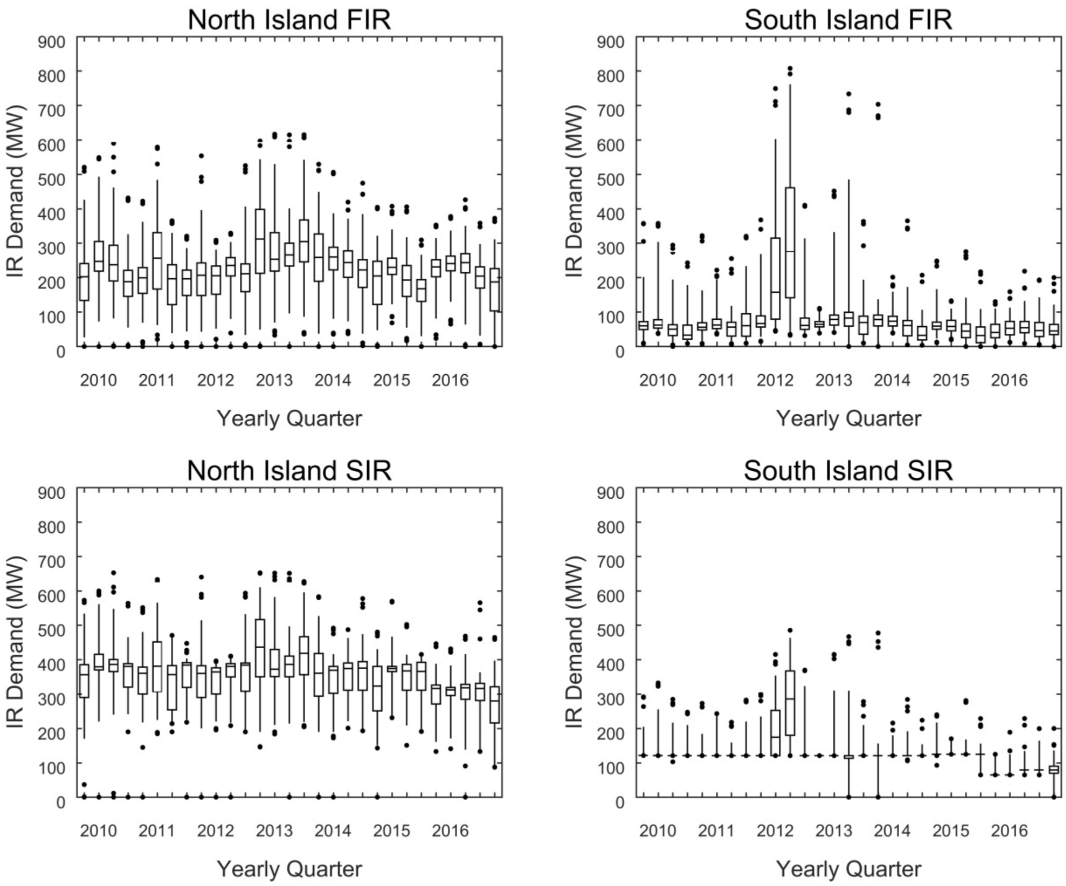

Figure 7.3: The distribution of demand for Instantaneous Reserves. The distribution is represented by a box and whisker plot. The top and bottom of the box are the 25th and 75th percentiles. The whiskers represent the 1st and 99th percentiles. The dots are the three maximum values and three minimum values. The time range of the data extends from the last quarter of 2009 to the last quarter of 2016.

Eventually HVDC transfer south became constrained by the available FIR, resulting in a relatively high reserve spot price, which in turn contributes to the energy spot price in the South Island. This is seen in Figure 7.2, where the South Island experiences its most consistently high spot prices since 2008. To alleviate the situation Tiwai Aluminum Smelter was brought in to provide Interruptible Load. However Meridian Energy gained control of the Smelter's IL offers, and gained considerable market power in the South Island FIR market. The Electricity Authority investigated the actions undertaken by the power companies, and Meridian Energy responded: stating that the reserve offer price reflected the value of water in the reservoir during the shortage (Blythe, 2012). If the reserve price was not raised then the energy price would have been increased was the justification for the high reserve prices given by Meridian Energy. Therefore, the IR costs of Figure 7.1 do not entirely reflect the cost of providing reserves, but are related to energy costs as well.

By 2013, these issues were not seen to the same degree, even though there were periods of high HVDC transfer. This was because Pole 1 was decommissioned by later 2012 and the new Pole 3 link was running with the ability to transfer power between the Poles if one of them tripped out.

The second feature of interest is the reduction of procured SIR in both Islands from the last quarter of 2015 to the last quarter of 2016. This is due to the SIR sharing between the two Islands, which was initiated as a result of the commissioning of Pole 3 and the upgrade to the HVDC controls. This allows reserve from one island to cover a loss of generation in another island. Previously sharing had been limited to FIR, where 50 MW was shared in the winter, and 25 MW in the summer. From 17th December 2014, FIR sharing limit was increased to 60 MW all year round, which seems to have had little impact on the amount of procured FIR. From 29th September 2015, SIR was allowed to share 60 MW between the islands, and then from 17th November 2016 the limit was increased to 220 MW, thereby creating the NMIR (Transpower, 2016e).

The availability of reserves is analysed by considering what has been offered in the past, and by looking at what could be offered in the future. Participants offer and decline to offer reserves for a number of reasons, whether because it is no longer cost effective to do so or the power station is decommissioned. The historic offers for reserves are presented for SIR in Figures 7.4, 7.5, and 7.6; similar figures for FIR are presented in Appendix I. A description of the various reserve offering profiles is given in Table I.1 in the appendix.

The historical offering of reserves shows a general decline in quantity in the recent past, but there are periods of increase and decrease. Large reduction in available capacity comes from the shutdown of thermal units. These include two Huntly Rankine units, New Plymouth, Otahuhu CCGT. However, two OCGTs have increased the reserve from Stratford. For Hydro generation in the North Island, there is a general trend to move away from TWDR as it requires energy to run in this mode. There is still a large amount of available reserve in the North Island, as long as generators are not constrained by providing energy.

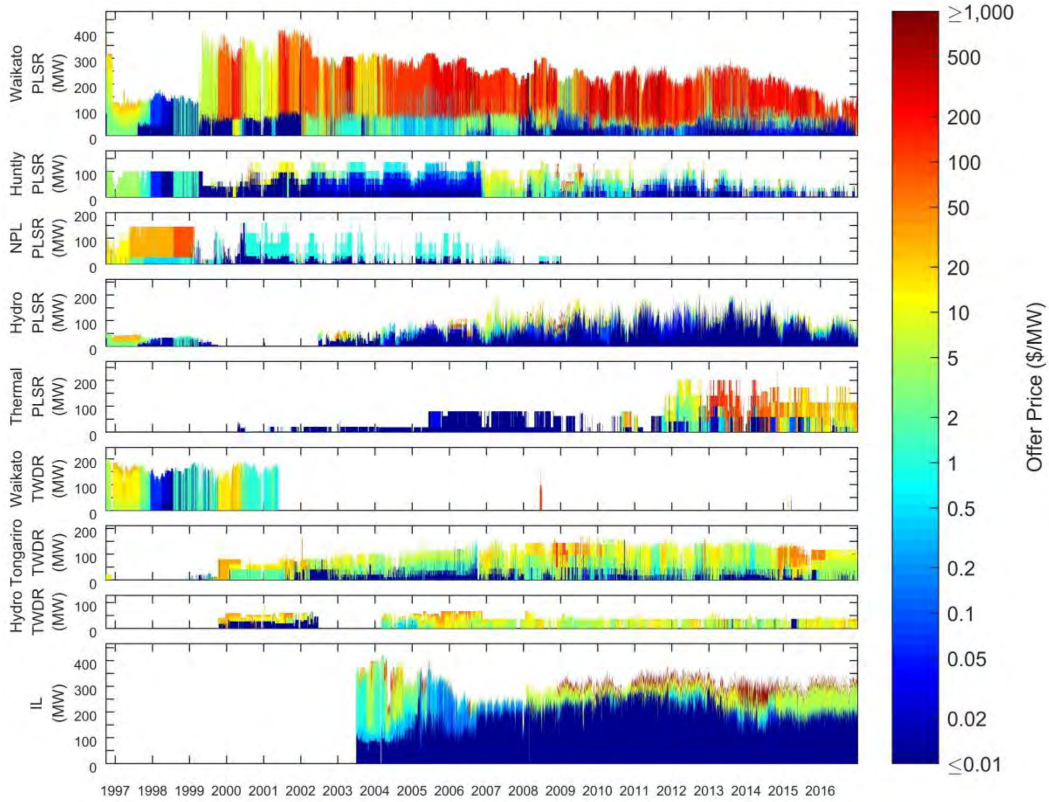

Figure 7.4: North Island SIR Offers. Each plot is produced by finding the highest offered reserve quantity out of each day since the Electricity Market has been in operation, except for IL which only has data since July 2003. Offers are grouped by blocks: NPL is New Plymouth power station; Hydro PLSR includes the Waikaremoana Scheme, Matahina, Mangahao, Patea, Tongariro Scheme, and the Wheao Scheme; Thermal PLSR includes the Te Awamutu gas turbine, Otahuhu CCGT, Poihipi Rd geothermal plant, and Stratford. Hydro TWDR includes the Waikaremoana Scheme, Matahina, and Patea.

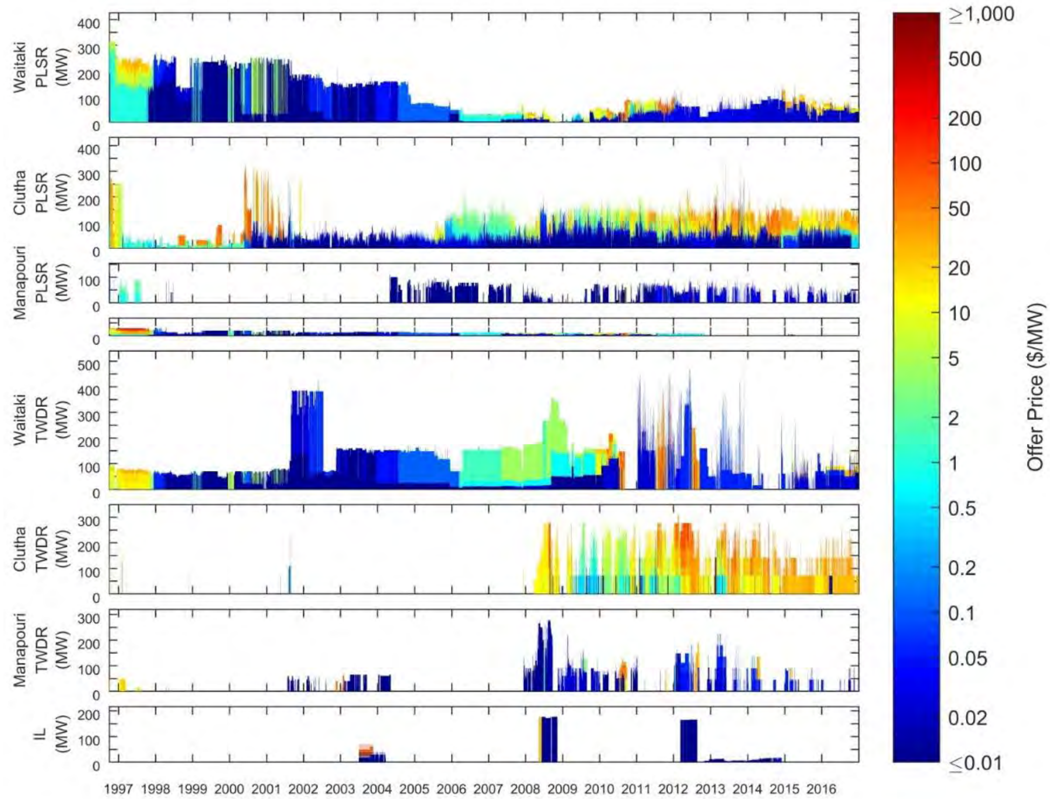

Figure 7.5: South Island SIR Offers. Each plot is produced by finding the highest offered reserve out of each day since the Electricity Market has been in operation, except for IL which only has data since July 2003. Offers are grouped by blocks: Waitaki does not include the two Tekapo stations; the fourth plot is for other South Island hydro generation, which includes Cobb, Coleridge, Highbank, and the two Tekapo power stations.

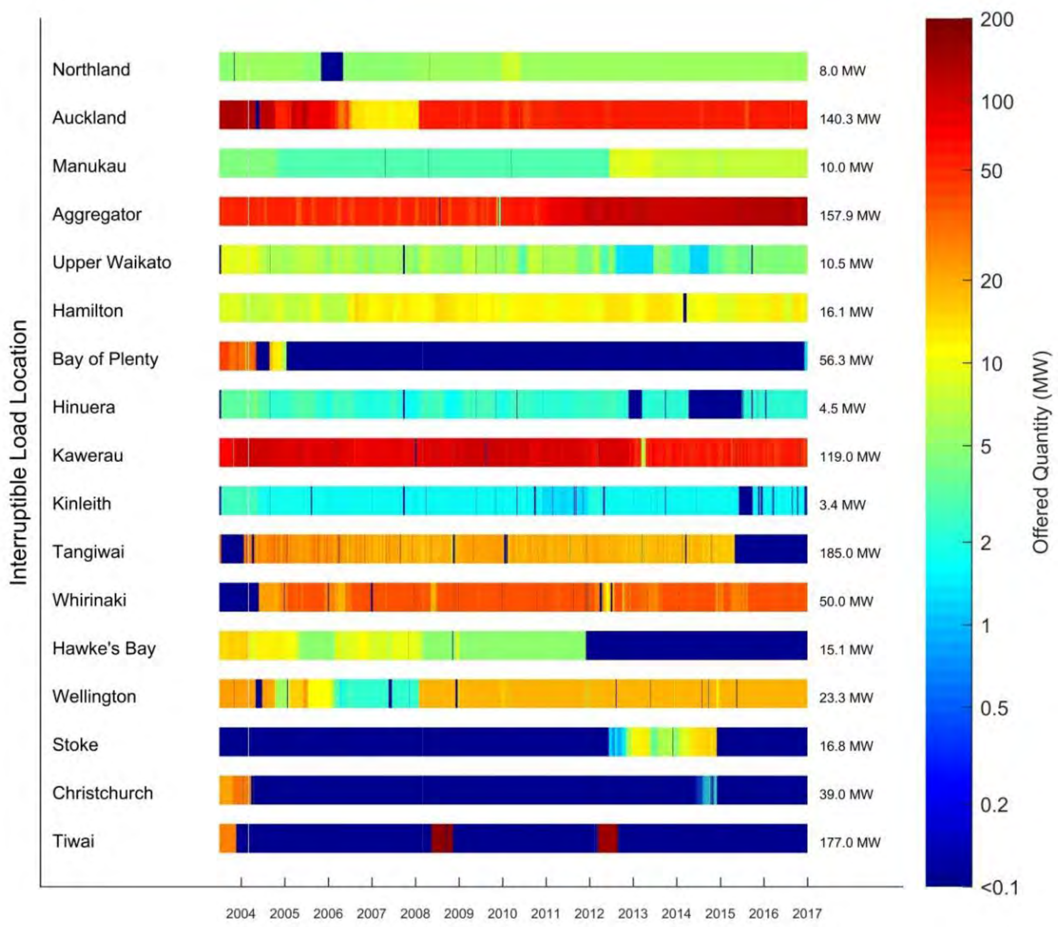

Figure 7.6: Offered SIR from IL providers. This plot was produced by taking the largest offer in each day and colouring the total offered quantity. This figure does not give any information about the price of the offered reserve. (Note: the blue colour generally implies the absence of an offer.) The numbers on the right side of the bar are absolute maxima. Aggregator also includes Glenbrook Steel Mill.

7.1.2. Frequency Keeping

In a similar manner to IR, the availability of FK reserve is analysed by first considering the historical cost of FK, the amount that has been procured historically, and what has been offered. Hydro generation has been the preferred source of FK, but thermal generation particularly from Huntly and more recently from Stratford has also supplied it.

FK had a steady cost of $50 million per annum from 2005 to 2012, except for 2008 where the costs reached close to $100 million, Figure 7.7. 2008 was a dry year which saw high spot prices both in the FK market and the wholesale energy market, which increased constrained-on costs. Since 2013, the cost of FK has reduced. It is unclear why the cost reduced in 2013 and 2014. It was possibly the result of Multiple Frequency Keeping (MFK) starting in the North Island in the middle of the 2013; however, analysis is not conclusive (Electricity Authority, 2015), but also could be due to decreased FK requirement in the South Island. From 2015 onwards, it is clear that the reduced cost is a result of reduced demand for FK reserve.

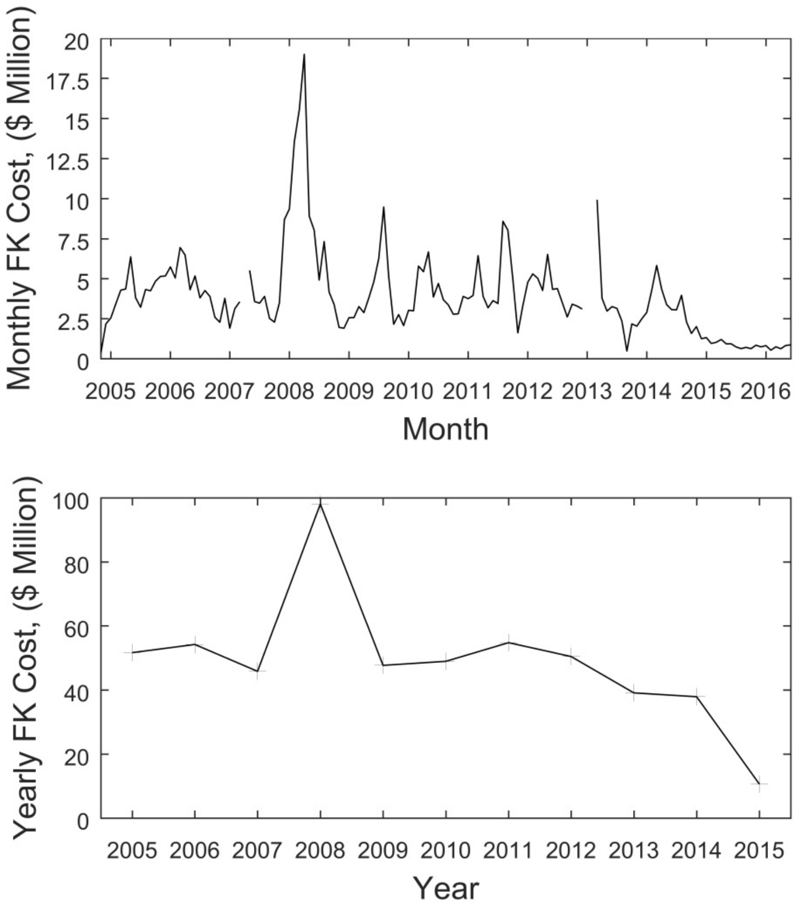

Figure 7.7: Monthly (Top) and Yearly (Bottom) FK costs. (The month of January is on the tick for the monthly plot.) 2007 and 2013 are missing data, so the yearly totals are estimates from the mean.

The demand for FK was higher in 2005, with 50 MW on average purchased in each island, than what was purchased in 2017. The demand for FK in the North Island, prior to MFK and FKC, was normally 50 MW except for a brief period of 100 MW, and the one exception of 150 MW. The demand for FK in the South Island was more dynamic, on average 50 MW, but periods of 25 MW in the early morning and periods of 75 MW were fairly common, with some exceptional cases reaching 100 MW. The highest combined amount of FK procured between the islands was 200 MW. By June 2008 the South Island no longer procured 75 MW just 50 MW or 25 MW. By July 2012 the South Island no longer procured 50 MW after trials starting in March, and mostly procured just 25 MW. The general decline can be seen in Figure 7.8.

With the upgrade of the HVDC Link in 2013 and the implementation of Round Power controls in 2014, the HVDC link has offered greater frequency management through FKC, and the requirement for FK has reduced. In 2015 the requirement was usually 20 MW in the North Island and 10 MW in the South Island, but several tests were done to see what would happen when no regulation signal was being sent to the generators, effectively 0 MW procured. Lastly in May 2016, FK was split evenly between the two islands, 15:15 MW.

The providers of FK have mostly been hydro generation: the Waitaki scheme is dominant in the South Island, whereas the Waikato scheme is dominant in the North Island. The market spread is seen in Figures 7.8 and 7.9. The maximum offered reserve is shown in Table 7.1, the offers are limited to a time period since the start of MFK, therefore some of them could have offered more in the past.

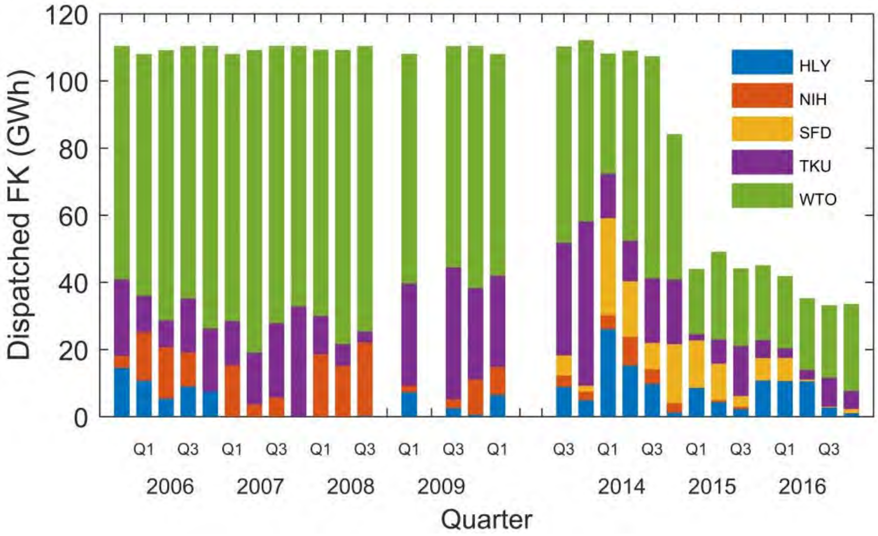

Figure 7.8: Demand for FK in the North Island, calculated from dispatched reserve. Limited data were available, as there is a big gap between 2010 and 2013. NIH (North Island Hydro) refers to Patea and Waikaremoana scheme.

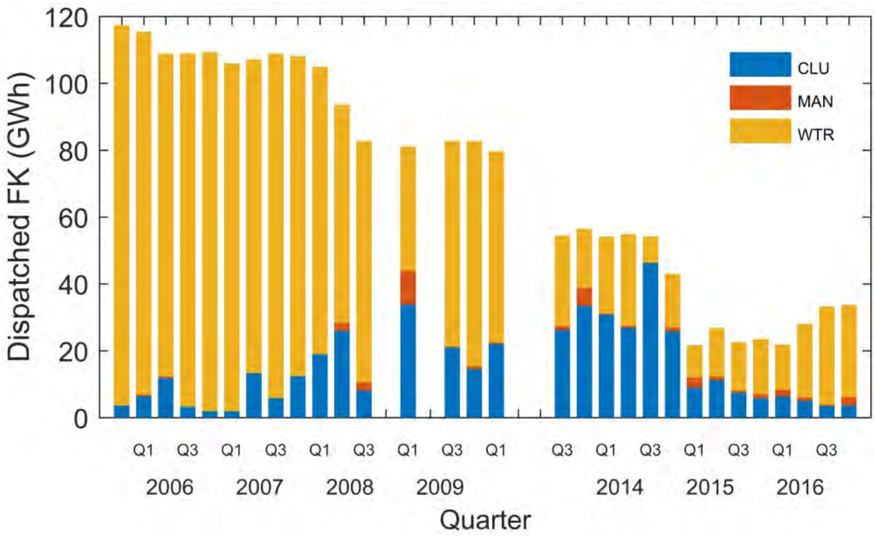

Figure 7.9: Demand for FK in the South Island, calculated from dispatched reserve. Limited data were available, as there is a big gap between 2010 and 2013.

Table 7.1: Maximum offered Frequency Keeping

Provider	Abbrev.	Max Offer (MW)
Huntly Unit 2	HLY2	10
Huntly Unit 4	HLY4	10
Huntly Unit 5	HLY5	34
Patea	PTA	15
Stratford 21	SFD21	38
Stratford 22	SFD22	40
Taranaki CC	SPL	50
Tokaanu	TKU	60
Waikaremoana	WKA	50
Waikato	WTO	50
Clutha	CLU	75
Manapouri	MAN	75
Waitaki	WTR	75

7.2. Grid Emergencies and Reserve Shortfalls

In practice generation capacity needs to be shared between both energy requirements and reserves. Therefore, if there is a shortage in energy offers, it can constrain the availability of reserves, which has happened on a number of occasions from 2014 to 2016. These are grid emergencies and usually result in reserve shortfalls, as energy requirements have higher precedent over reserve in the dispatch. The causes of these events are an unanticipated high demand, with insufficient incentive or ability for participants to offer energy and reserve to relieve the emergency. This section introduces the issues recognized by Transpower and the Electricity Authority, and considers what could be required in the future under high wind penetrations.

There are three historical events of interest:

1. On the 27th May 2014, for trading period 16 (7:30 am), there was insufficient reserve and a grid emergency was declared. Real time prices reached \$100,000 MWh indicating a reserve shortage, and final prices at Haywards were \$1,033.96 MWh for TP16 (Electricity Authority, 2014). North Island SIR price reached \$947.34 MWh.
2. On the 19th August 2014, particularly for trading period 37 (6:00pm), insufficient reserve resulted in a grid emergency. North Island SIR prices reached \$9,000 MWh, and Haywards final spot prices were \$8,714.53 MWh. Transpower have written a report on the event (Transpower, 2014c).
3. On the 26th July 2016, particularly for trading period 17 (8:00am), although there was no grid emergency declared and there were sufficient reserves, the energy price reached \$4,756.90 \$MWh at Haywards, and the North Island FIR price reached \$9,851.72 MWh. This indicated that the system was approaching its limit.

Although this only lists two cases of insufficient reserve, there were a number of warnings that occurred as well. Recorded in the Transpower and Electricity Authority reports (Electricity Authority, 2014) (Transpower, 2014c), there were several causes of the 2014 events:

1. Unexpected high demand for electricity, as a result of cold weather, coupled with low wind farm output.
2. Errors in demand and wind generation create significantly different pricing signals in the scheduling process, coupled with a steep price curve at the end of the offer stack.
3. Within gate closure generation outages.
4. Insufficient generation offers: some CCGT plant could not be offered with 12 hour start up time, and South Island hydro generation limited offers to avoid increasing HVDC transmission charges.

To analyse what happened for these three events, generation offers and reserve offers are reviewed against the dispatches sent: the results are shown in Table 7.2 to 7.5. Two other events were also presented, which are the maximum demand peaks for the morning and the evening for the period from November 2012 to April 2016; this considers wind generation as negative demand, and should represent the greatest necessary dispatch of conventional generation.

Table 7.2: Offers and dispatch of energy generation for three of five trading periods of interest.

Event		**15th July 2013 TP36**				**27th May 2014 TP16**				**19th August 2014 TP37**			
	Historical	Offers[e]				Offers				Offers			
Energy	Maximum MW[a]	Price $/MWh	Quantity MW	Max MW	Dispatch MW[f]	Price $/MWh	Quantity MW	Max MW	Dispatch MW	Price $/MWh	Quantity MW	Max MW	Dispatch MW
North Island		Haywards FP $95.61				Haywards FP $1,033.96				Haywards FP $8,714.53			
Cogeneration	324[b]	0.01	193	283	174	0.01	147	244	147	0.01	182	280	181
Geothermal	1049[b]	0.01	629	661	629	0.00	795	826	795	0.01	821	841	821
Thermal	2735	65.02 460	1909.5 201	2126	1782.3	500	1456.5	1516	1315.5	595	1255.7	1266	1122.1
Hydro	1903[c]	95.55 97.5	1177.5 175	1464	1209.8	260	1387.5	1570	1307.5	3000	1509	1584	1469.4
Subtotal	6011	95.55 97.5	3909 376	4534	3795.1	500	3786	4156	3565	3000	3767.7	3971	3593.5
North Island Wind	573[d]	0.01	200.6	513	160.1	0	0	513	1.2	0.01	46.61	564	71.1
Total	6584	95.55 97.5	4109.6 376	5047	3955.2	500	3786	4669	3566.2	3000	3814.31	4535	3664.6
South Island		Benmore FP $90.10				Benmore FP $976.10				Benmore FP $8,016.33			
Hydro	3687[c]	89.21 109.64	2896 45.5	3088	2867.4	975 5200	2714.5 5	2874	2694.5	5200	2968	3105	2943
South Island Wind	98	0.01	22.2	98	22.3	0.01	52.5	98	54.6	0	0	98	0
Total	3785	90 109.64	2918.2 45.5	3186	2889.7	975 5200	2767 5	2972	2749.1	5200	2968	3203	2943
New Zealand	10369				6844.9				6315.3				6607.6
HVDC Transfer North					715.7				543.4				789.6

a. Historical Maximum MW, this is the maximum quantity offered in the generation offers from March 2004 to December 2016.
b. For aggregates of generators that are mostly independent, the maximum is derived from the summation of individual maximums.
c. However for a system of generators, such as a hydro scheme, the maximum is the largest combined capacity.
d. For North Island wind generation the maximum is partly adjusted by the wind farm name plate capacities.
e. Offer information is reduced from its 5 bands down to offers above and below the marginal price. This cannot be done entirely accurately for each trading period, as the dispatch every 5 minutes can change the marginal generator. Also other constraints can impact who is the marginal generator and how many there are, as the system can separate.
f. The dispatch is the last change in instructions to generators within the trading period. (Note, these footnotes also apply to Table 7.4.)

Table 7.3: Offers and dispatch of Instantaneous Reserve for three of five trading periods of interest.

Event		**15th July 2013 TP36**				**27th May 2014 TP16**				**19th August 2014 TP37**			
	Historical	Offers				Offers				Offers			
FIR	Maximum MW[a]	Price $/MWh	Quantity MW	Over Supply MW[b]	Dispatch MW	Price $/MWh	Quantity MW	Over Supply MW	Dispatch MW	Price $/MWh	Quantity MW	Over Supply MW	Dispatch MW
North Island		$8.46				$10.70				$150.27			
Thermal	230.1	0.50 20.02	68.5 9	77.5	50	0.04 75	38.6 64	102.6	0	5	80.4	80.4	50
Hydro	991	8.5 15	157.2 22	66	149.6	4.34 230	160.2 44	145.1	66	50 300	110.9 18	72.9	87.5
North Island IL[c]	494.7	8 800	92.2 7	-	92.2	4.19 800	122.1 6	-	122.2	4.99 800	76.4 6	-	82.4
Total	1715.8	8.5 15	317.9 38	143.5	291.8	4.19 75	321 114	247.7	188.2	50 300	267.7 24	153.3	219.9
South Island		$0.01				$0.00				$0.00			
Hydro	1009.5	0.01 0.02	70 117	60	60.7	0.01	176	44	0	0.01	174	51	0
South Island IL[c]	193.2	0.00	3.3	-	3.3	0.00	10.2	-	8.5	0	11.5	-	6.7
Total	1202.7	0.01 0.02	73.3 117	60	64	0.00 0.01	10.2 176	44	8.5	0 0.01	11.5 174	51	6.7
SIR													
North Island		$34.58				$947.34				$9,000.00			
Thermal	341.3	20.02	137	137	126.1	90	162	162	0	5	113.9	113.9	50
Hydro	1135.1	7.99 140	202.3 10	81.7	199.2	230	285	215.5	75.5	300	168.9	106.5	96.7
North Island IL[c]	799.4	10.29 801	119.7 7	-	119.7	903	191.7	-	191.7	10.29	157.7	-	157.7
Total	2275.8	20.02 140	459 17	218.7	445	903	638.7	375.7	267.2	300	440.5	220.4	304.4
South Island		$0.05				$342.39				$216.40			
Hydro	1609	0.05 35	179 29	90	116.3	10	201	54	87	80	183	70	105.4
South Island IL[c]	232.8	0	4.7	-	4.7	0	13.7	-	13.3	79	15.7	-	15.7
Total	1841.8	0.05 35	183.7 29	90	121	10	214.7	54	100.3	80	198.7	70	121.1

a. Historical Maximum MW, this is the combined partially loaded spinning reserve and tail water depressed reserve offered from groups of generators. The maximum is derived from data from the start of the Wholesale market, October 1996, to December 2016.
b. Over Supply MW, in the formulation of the Scheduling, Pricing, and Dispatch tool the amount of reserve procured is limited by the maximum generation constraint, therefore the Over Supply column is how much over this maximum the combined energy and reserve offers would be if it were all dispatched. (These footnotes also apply to Table 7.5.)
c. The dispatch of some Interruptible Load providers was not known, so an estimate based from the offer is provided instead.

Table 7.4: Offers and dispatch of energy generation for the last two of five trading periods.

Event		12th August 2015 TP16				26th July 2016 TP17			
Energy	Historical Maximum MW	Offers Price $/MWh	Offers Quantity MW	Offers Max MW	Dispatch MW	Offers Price $/MWh	Offers Quantity MW	Offers Max MW	Dispatch MW
North Island		Haywards FP $85.20				Haywards FP $4.762.39			
Cogeneration	324	0.01	212.5	283	212.5	0.01	205	279	200.3
Geothermal	1049	0.00	860	860	860	0.01	765	765	765
Thermal	2735	85 95	1367.5 313.1	1684	1289.6	4997 5000	922.7 52	989	744.6
Hydro	1903	70.07 98.06	1456.5 97	1604	1387.8	4995.07	1523.5	1563	1474.8
Subtotal	6011	85 95	3896.5 410.1	4431	3749.8	4997 5000	3416.2 52	3596	3184.7
North Island Wind	573	0.01	37.7	573	37.4	0.01	12.7	573	11.3
Total	6584	85 95	4232.3 112	5004	3787.2	4997 5000	3428.9 52	4169	3196
South Island		Benmore FP $80.29				Benmore FP $63.33			
Hydro	3687	90 124.46	2911 61	3078	2911	60 68.07	2969.5 258.5	3259	2971.8
South Island Wind	98	0.01	6.3	98	8.4	0.01	60.44	98	61.8
Total	3785	90 124.46	2917.3 60	3176	2919.4	60 68.07	3029.9 258.5	3357	3033.6
New Zealand	10369				6706.5				6229.5
HVDC Transfer North					701.2				839.6

Table 7.5: Offers and dispatch of Instantaneous Reserves for last two of five trading periods.

Event		12th August 2015 TP16				26th July 2016 TP17			
		Offers				Offers			
FIR		Price $/MWh	Quantity MW	Over Supply MW	Dispatch MW	Price $/MWh	Quantity MW	Over Supply MW	Dispatch MW
North Island		$5.00				$9,851.72			
Thermal	230.1	5 8	58.2 42.8	101	91.1	3	80.4	80.4	80.4
Hydro	991	0.99 15.06	55.6 51.3	55.7	63.9	40	82.5	61.3	61.9
North Island IL	494.7	0.01 900	78 6	-	42.7	600	78.4	-	78.4
Total	1715.8	5 8	191.9 100.1	156.7	197.6	600	241.3	141.7	220.7
South Island		$0.00				$0.01			
Hydro	1009.5	0.01	121	56	0	0.01 0.02	16 159	163	6.8
South Island IL	193.2	0	0	-	0	0	0	-	0
Total	1202.7	0.01	121	56	0	0.01 0.02	16 159	163	6.8
SIR									
North Island		$39.94				$19.17			
Thermal	341.3	8	171.9	171.9	150.1	3	113.9	113.9	80.4
Hydro	1135.1	16.21 800	208.9 13	174.1	185	19.17	144.4	121.4	68.4
North Island IL	799.4	10.29 900	105.1 6	-	70.9	10.29 600	169 6	-	169
Total	2275.8	16.2 800	485.9 16	346	406	19.17 600	427.3 6	235.3	317.8
South Island		$0.02				$0.50			
Hydro	1609	0.02 0.05	138 35	93	125	0.5 15	154 50	192	79.5
South Island IL	232.8	0	0	-	0	0	0	-	0
Total	1841.8	0.02 0.05	138 35	93	125	0.5 15	154 50	192	79.5

To make referring to each event easier, each event will be listed in chronological order, and be called E1, E2, E3, etc.

- E1 is the 15th July 2013, Trading Period 36, and is the largest evening peak minus wind generation over the analysis period.
- E2 is the 27th May 2014, Trading Period 16, and is the first event with insufficient reserves.
- E3 is the 19th August 2014, Trading Period 37, and is the second event of insufficient reserves.
- E4 is the 12th August 2015, Trading Period 16, and is the largest morning peak minus wind generation over the analysis period.
- E5 is the 26th July 2016 Trading Period 17, and is a case where HVDC transfer just about constrained North Island energy and reserves.

Although E1 had the greatest demand for energy in the North Island out of the five events, it was the least constrained of the five trading periods. Before the recent closure of thermal units, there has not been an issue of insufficient generation capacity installed (a second Huntly Rankine unit was decommissioned in June 2015, Otahuhu CCGT in September 2015, and Southdown in December 2015). The causes of insufficient reserve have been sub-optimal scheduling of resources, resulting from, for example, the lack of offers from Otahuhu CCGT and Taranaki CCGT for E3.

E5, with the smallest demand for energy in the North Island, had the greatest dispatch of North Island hydro generation out of the three events. This is largely due to the small amount thermal generation being offered with only 744.6 MW being dispatched compared to 1,315.5 and 1,122.1 MW for the other constrained events, E2 and E3. The lack of thermal generation was because of the lack of offers from Huntly Rankine units and Taranaki CCGT. Since the closure of Otahuhu CCGT, Southdown, and the second Huntly unit, it is more important to keep thermal generation available.

The results from simulating the dispatch process, Figure 7.10, show that for higher penetration of wind generation that there is still a large demand for thermal capacity. Even though the simulation did not simulate changes to demand side management to reduce the peak thermal requirement, there is still expected to have a large demand for thermal capacity. However the utilisation of thermal generation has decreased, as it is the goal to reduce thermal energy consumption, but the incentive for that thermal capacity to remain has reduced, unless electricity prices for those small periods is large. Therefore reducing reserve requirements and freeing North Island hydro generation for electricity generation would have a large value, especially as a single HVDC pole risk becomes the dominant risk on the North Island power system.

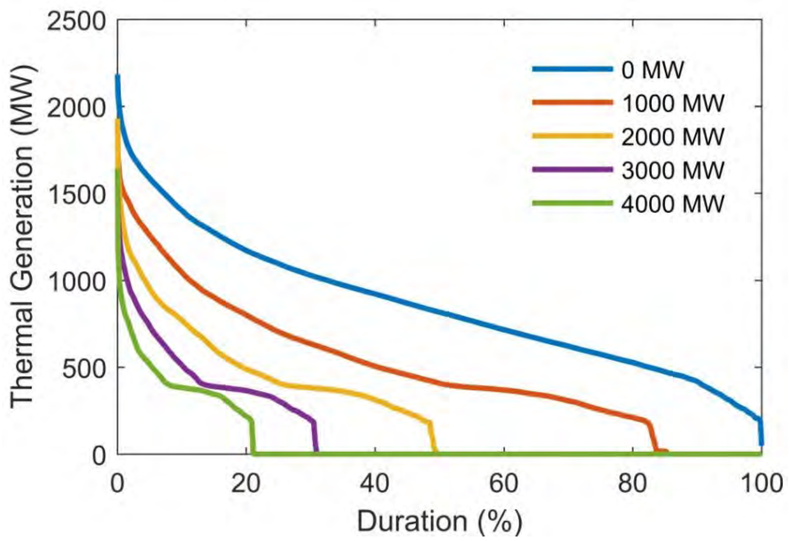

Figure 7.10: Generation duration curves for the total thermal generation. Shown for the historical case (0 MW), and for four of the wind generation scenarios. The data is derived from the dispatch model, over a period of three years from December 2012 to November 2015.

8. Requirement for New Ancillary Services

This section provides recommendations for changes to frequency control Ancillary Services (AS) (currently Frequency Keeping (FK) and Instantaneous Reserves (IR)) in New Zealand. It begins by reviewing the general principles of frequency control ancillary services and, more generally, reserves, and issues that must be considered in New Zealand.[3] It then considers how increasing variable renewable generation might affect the energy market, since this also affects the provision of frequency control ancillary services. Next a discussion of frequency control in Ireland is presented to highlight the impact of large wind penetration on AS requirements. Changing requirements for ancillary services with increasing wind generation are summarised, with recommendations for new ancillary services and market arrangements.

8.1. General Principles of Ancillary Services

An electric power system supplies energy, in the form of electrical power, to enable an economy to function. From the first reticulation in the late 19th century to supply lighting, electric power systems have grown to provide energy to industry, businesses, and households. Electricity plays a role in peoples' lives every day, and as such forms a 'life-line' infrastructure.

Secondary to the supply of energy is the supply of frequency control reserves. Reserves are vital to the operation of the electric power system, but are not in themselves primary products. The main costs of reserves, in approximate order of size, are capacity of plant (MW), energy sales forgone in providing reserves (MWh), and additional infrastructure required to provide reserves. The two frequency control ancillary services in New Zealand, FK and IR, are procured from markets through ancillary services contracts.

Since reserves are secondary to energy, energy has primary consideration in the operation of the electric power system. The choice of plant to generate is primarily made by the energy cost they offer into the energy market, which in a highly competitive market should reflect their respective short run marginal costs. For example, the choice between a thermal unit, with greater inertia than a hydro unit, and a hydro unit with excessive water, is made by the lowest cost fuel source rather than the size of inertia. This has been rightly established as the best way of achieving the greatest efficiency, as most electricity markets dispatch power, and very few power systems consider inertia or droop in the choice of generators. However, in the New Zealand electricity market, the dispatch of plant is changed if there is insufficient reserve available. This is through the co-optimised dispatch of energy and IR. As the penetration of Variable Renewable Energy (VRE) increases, the dispatch of energy may also need to factor in requirements of inertia and droop.

In the New Zealand power system and electricity market, a competitive procurement approach is taken for frequency control ancillary services. IR is procured by matching offers with requirements through co-optimisation in the energy market. FK ancillary services are procured through competitive supply offers, to meet the required demand at each point in time. A market based approach is taken because of its benefits in allocative and dynamic efficiencies. Benefits of competitive procurement are:

1. Competition amongst suppliers delivers the most cost effective result (allocative efficiency), although this assumes a sufficient number of providers to compete effectively;
2. Decentralised planning of investment minimises the error of a single planner; and

[3] Frequency control reserves include frequency control ancillary services, such as IR and FK, as well as 'back stop' measures such as automatic under frequency load shedding (AUFLS), which is not itself an ancillary service.

3. Competition drives innovation in the provision of ancillary services (dynamic efficiency).

A market based approach does however give rise to a number of challenges, such as:

1. The risk of poor design in ancillary services market leading to unintended consequences, which often results, ironically, in a centralised corrective response.
2. Compartmentalising an ancillary service, or a range of services, to a product for the purpose of creating competition, may not facilitate best practice at all times, or may miss certain subtle aspects of ancillary services, thereby creating inefficiencies.

A further challenge is the tension between creating a market with enough parties to create sufficient competition, but not so many parties that it becomes inefficient. It may be that two parties are sufficient, which is what practically occurs in the South Island.

This report addresses the question of how the frequency control ancillary market should be changed, if at all, to: (1) accommodate increasing amounts of variable renewable generation; while (2) providing an incentive for efficient and appropriate investment in generation capacity, energy use and frequency management infrastructure.

8.2. Energy Market Considerations

A discussion of issues in the energy market related to increased variable renewable energy is relevant, since historically plant that participates in the energy market has also provided reserves. Earlier work in this report, Section 4, has shown that as variable renewable generation increases, it will be subject to greater levels of energy curtailment (spill). Spill is expected to be a result of an over-supply of must run generation during low demand periods, or of high water storage levels.

A further consideration is, if the wholesale market is sufficiently competitive, suppliers should face competitive pressure to offer at, or near, their short run marginal cost. For a renewable generator this is close to zero, meaning that as more renewable energy is added, the wholesale spot price approaches zero. New Zealand has historically operated in an environment where the wholesale spot price is set by the short run marginal cost of thermal generation, with hydro water values derived from the basis of opportunity cost. In turn peak prices should reflect the long run marginal cost of peaking generation and signal the next generation unit investment. However as New Zealand reaches 100% renewable generation, under the current market, long periods of very low wholesale prices may well occur. Amongst these there may be periods of high price, determined by hydrology, such as perceived or real shortage of water for future generation. This may not be sufficient to signal the next generator investment.

With both of these factors at play (spill of wind as more wind generation is added and the real risk of decreasing prices as more variable renewable generation is added) there would appear to be an insufficiently strong signal, and too much uncertainty, to invest in wind generation or any other variable renewable generation. The uncertainty is heightened by other factors such as demand uncertainty. These highlighted challenges may require some other mechanism to ensure appropriate investment outside of the energy market, such as a capacity market, or subsidies, or another pricing mechanism. These changes may require the modification of ancillary services and how they relate to the energy market.

Notwithstanding the above, SPD and nodal pricing provide an efficient platform for real-time dispatch and allocation of generation resource to minimise generation cost and losses, as well as signal transmission constraints. Moreover, the current wholesale spot market values storage, as hydro generators manage reservoir levels to maximise profit, which coincides with efficient management of the hydro reservoir to manage low inflow periods. These incentives should be maintained when additional incentives for VRE are designed.

8.3. The Approach of Ireland

The synchronous electrical power system of Ireland, consisting of the Republic of Ireland and Northern Ireland, is a slightly larger network than the North Island power system, with a peak demand just above 6,300 MW (EirGrid, 2016a). It currently has an installed wind capacity of 3,736 MW (IWEA, 2017). Ireland does have two connections to the UK's mainland grid, but they are small – the largest is a 500 MW HVDC connection. Since Ireland is a similar size to New Zealand, and is further developed in wind generation, it is helpful to describe the changes Ireland has made to their AS markets.

Before the rapid development of wind generation, Ireland was mainly supplied by fossil fuels, such as Gas, Coal, Distillate Oil, and Peat. In addition, there are four main hydroelectric schemes, which provide a total capacity of 216 MW, and a pumped storage plant of 292 MW at Turlough Hill, commissioned in 1974 (EirGrid, 2016a). However, these are relatively minor hydro resources in comparison to New Zealand's hydro resource. The large dependency upon fossil fuel generation, and the rising concern of climate change, has led to accelerated development of renewable energy in Ireland. The latest targets are to reach 40% renewable energy for electricity generation by 2020 (DCENR, 2015), 12% for heating, and 10% for transport. In order to achieve the electricity target, several schemes have been initiated to incentivise more renewables. These incentives have been in the form of a Power Purchase Agreement / Feed in Tariff, 'Renewable Energy Feed in Tariff' RE-FIT. Three of these schemes have been initiated: the first one sought to purchase 400 MW of renewable capacity from 2006 to the end of 2009, with a 15 year contract; the second one, more ambitious in scale, sought to increase renewable capacity by 4,000 MW, through applications that closed at the end of 2015; and the third sought to obtain 150 MW of high efficiency Combined Heat and Power, and 160 MW of Biomass generation.

These schemes have seen a large development of on-shore wind farms with 1,406 MW in 2010 (IWEA, 2012) increasing to a total of 3,736 MW in June 2017. With such large penetration of wind energy, there was concern about how the grid would operate, which has led to several studies being conducted. The first study of note was the All Island Grid Study (DCENR and DETI, 2008), which characterised the economic benefits of wind generation. However, the All Island Grid Study did not capture the issues of dynamic performance, therefore further study was conducted and resulted in the All Island TSO Facilitation of Renewables Studies (EirGrid, 2010). The area of greatest concern was system stability after the loss of the largest infeed, that is would the frequency recover fast enough after the loss of the largest generator or HVDC pole. The concern comes from the reduction of inertia that wind generation gives rise to. A standard was set to ensure that inertia did not get too low. This is the System Non-Synchronous Penetration (SNSP) limit defined by the following equation:

$$\frac{P_{wind} + P_{import}}{P_{load} + P_{export}} < limit\ (\%)$$

Initially set at 50%, this ensured that no more than 50% of local island demand and export was provided by asynchronous generation. Since being set at 50% the limit was increased to 55% at the start of 2016, and then to 60% at the start of 2017, as the system became more adept at handling greater levels of wind generation (EirGrid, 2016b). If the instantaneous wind output goes above this limit then wind generation is curtailed. The system operator sends a signal to the wind farms to follow a set point in real power, as it is defined in the Grid Code, from Wind Following Mode to Active Power Control Mode (WFPS1.5.3.1 and WFPS1.5.3.2) (EirGrid, 2015a). Within Active Power Control Mode, the wind farm also has to provide a droop frequency response.

The consequence of having the SNSP limit is that at times wind generation has to be curtailed. The amount that has been curtailed in total has historically been somewhere between 2 to 5% of the available wind energy (EirGrid, 2017). In 2016 roughly 50% of the curtailed generation was because of the SNSP limit and other stability issues. The other 50% was due to network constraints. Curtailing of wind generation is undesirable, as it is expensive and it makes it more difficult to achieve renewable energy targets. To minimise curtailment, the DS3 programme (Delivering a Secure, Sustainable Electricity System) aims to minimise curtailment by improving the dynamic performance of the grid, and raising the SNSP limit to the theoretical maximum of 75%.

Since the largest infeed has been a major factor in determining the SNSP limit it is important to analyse how contingencies are managed. It is set in the EirGrid Operating Security Standard (OSS) (EirGrid, 2011) that for an N - 1 contingency or the loss of the largest power in-feed that no supply should be disconnected. This implies that for these contingencies, the frequency should remain above 48.85 Hz – the first disconnection frequency of the Automatic Low Frequency Demand Disconnection (ALFDD) scheme. Subsequent blocks of ALFDD disconnect in steps of 0.05 Hz until 48.5 Hz. The total quantity of demand that can be lost is about 60% (Young, 2009) (ESB, 2005). The frequency limit of 48.85 Hz does not correspond to the frequency limit set out in the OSS of 48.0 Hz. For exceptional events the allowable frequency range is from 47 Hz to 52 Hz. The largest in-feed could be the 464 MW Great Island CCGT, the East West Interconnector at a capacity of 500 MW, or could be set by any future higher capacity HVDC links, such as the proposed Celtic interconnector of 700 MW.

The Irish grid handles contingencies with a similar resilience to New Zealand. For example, the Great Island CCGT tripped at 470 MW on 14 March 2015, causing the grid to reach a minimum frequency of 49.306 Hz within 5 seconds. A similar event occurred the day before, with 477 MW lost from the Great Island CCGT disconnecting, but only resulted in a minimum frequency of 49.581 Hz. Clearly there is variation in inertia and response times between these two days. The schemes in place to manage contingent events are Interruptible Load triggered at 49.3 Hz, Moyle Interconnection static reserve, Turlough Hill pump storage facility, and the rest of the Primary Operating Reserve (POR). More details can be found in the Grid Code, and a Transpower summary (Young, 2009).

To increase the SNSP limit, and thereby minimise the amount of wind curtailed, Ireland has established the DS3 programme to introduce a new set of AS to mitigate the effects of wind generation. Before introducing the new AS, it is helpful to consider the original services, which are listed below (EirGrid, 2015a):

- Primary Operating Reserve, POR. Defined as the MW output at the minimum frequency within 5 to 15 seconds after an event. This includes IL obtained through the Short Term Active Response (STAR) programme. A generation unit is expected to have 5% of its capacity capable of being offered as POR.
- Secondary Operating Reserve, SOR. MW output fully available and sustainable from 15 seconds to 90 seconds after an event. A generation unit is expected to be able to provide 5% of its capacity as SOR.
- Tertiary Operating Reserve band 1, TOR1. MW output fully available and sustainable from 90 seconds to 5 minutes after an event. A generation unit is expected to be able to provide 8% of its capacity as TOR1.
- Tertiary Operating Reserve band 2, TOR2. MW output fully available and sustainable from 5 minutes to 20 minutes after an event. A generation unit is expected to be able to provide 10% of its capacity as TOR2.

- Replacement Reserve, RR. MW output fully available and sustainable from 20 minutes to 4 hours after an event.
- Substitute Reserve, SR. MW output fully available and sustainable from 4 hours to 24 hours after an event.

In comparison to New Zealand's AS, POR is similar to Fast Instantaneous Reserve (FIR). New Zealand has a 6 second definition, whereas Ireland has effectively a 5 second definition. SOR, TOR1, and TOR2 as a whole correspond to New Zealand's Sustained Instantaneous Reserve (SIR). New Zealand does not further delineate time resolutions as there is a large amount of flexible hydro generation compared to Ireland's more inflexible thermal generation. Hence there is no need for Replacement Reserve and Substitute Reserve as these can be easily met through the dispatch process. Another important contrast is that generation units have requirements for ancillary service capability through the Grid Code, which is not the case in New Zealand. This highlights the way AS are procured in Ireland; in essence they have a minimum mandatory requirement but are dispatched based in accordance with the System Operator's needs, and are paid at a rate determined by a regulated tariff set every year (EirGrid, 2015b). In contrast New Zealand has a regular 30 minute based voluntary auction for IR.

Ireland has mandatory requirements for generators to provide Governor Droop, as well as for the interconnectors to provide droop. If a generator does not comply with Governor Droop requirements it is liable to a charge or penalty (EirGrid, 2016c). Secondly generators greater than 60 MW are required by the connection conditions to be connected to the Automatic Generation Control (AGC) system, and able to be controlled within the AGC limits by the System Operator. This is equivalent to New Zealand's FK, which is mandatory in Ireland, but is a voluntary offer based auction in New Zealand.

The new set of AS introduced as part of the DS3 Programme in addition to the original AS are as follows (SEM, 2013):

- Synchronous Inertial Response, SIR. The intent of this AS is to incentivise individual thermal units to operate at lower power outputs, and therefore increase the number of units synchronised to the grid and the inertia. It also incentivises synchronous compensators.
- Fast Frequency Response, FFR. This AS requires power to be achieved by 2 seconds and be sustained until 10 seconds. This power is required to be greater than the power from 10s to 20s. This is intended to specifically incentivise fast frequency response from converter based energy systems.
- Fast Post-Fault Active Power Recovery, FPFAPR. This AS incentivises fast recovery of real power output after a voltage disturbance. This is to avoid frequency transients as a result of voltage disturbances. A unit has provided this service if it can recover to 90% of its pre-fault active power output.
- Ramping Margin, 1 hour, 3 hours, and 8 hours; RM1, RM3, and RM8. This AS ensures sufficient ramping capacity to manage renewable generation variability. The definition of the reserve is how many MW can be ramped up within the time horizon, for RM1 this is one hour, and sustained for the output duration, for RM1 it is two hours. The output duration for RM3 and RM8 is 5 hours and 8 hours respectively.
- A distinction is made in the current AS of RR, a distinction between de-synchronised and synchronised. The time range for RR is shortened from 4 hours to 1 hour to separate it from RM1. Lastly SR is no longer required as an Ancillary Service.

With the development of new ancillary service products there has been a change of the procurement method from the current regulated tariff approach. Procurement design is ongoing with details still to be finalised; final implementation is expected in late 2018. The high level goal of the system planners is to shift towards a more competitive approach by having an auction based procurement approach. However, if for any given system service (AS) it is felt that there is insufficient competition, procurement will revert back to a regulated tariff system. Such a decision will be made through a pre-qualification process which seeks to determine the level of interest in a product. The procurement of the AS will be by auction run yearly, and so capability will be established instead of availability. The requirement for each service will be established by a volume calculation, completed by the TSO, based on anticipated changes in generation and reserve mix in the upcoming year. The auction would establish contracts for one year with existing suppliers, and potential 15 year contracts with new investors for added incentive of entry. Payment will be based on whether the supplier was utilised in any given trading period, although take-or-pay contracts will also be considered (SEM, 2014).

This overview of Ireland’s development towards greater renewable energy penetration has highlighted the differences between New Zealand and Ireland. Ireland has taken a proactive approach to reaching its renewable energy targets, compared to New Zealand’s ‘let the market decide’ approach. Ireland has introduced subsidies through the RE-FIT program, increasing the penetration of renewable energy substantially, which has come at a relatively minor direct cost of curtailing 2 to 5% of wind generation in the last half decade. In order to reduce curtailment, system services have been developed to incentivise greater resilience to disturbances, and thereby increase the maximum possible instantaneous share of converter based renewables. Value has been seen in frequency maintaining services with a faster response time, which needs to be valued more in New Zealand as inertia reduces.

8.4. Future of Ancillary Services in New Zealand

Before considering the recommendations of this research, it is important to consider the perspective of the System Operator and Electricity Authority on the future development of AS. Focus has been placed on improving clarity around normal frequency management to give clearer indication of requirements for investors. IR improvements have been sought by valuing the full response of a service provider, not just the response at 6 seconds and the average response over 60 seconds.

Normal frequency management, both FK and Governor Droop, has been a significant area of focus for Transpower and Electricity Authority since the results of Wind Generation Investigation Project were published in 2008 (Electricity Commission, 2010). This has led to a number of reports and consultations with industry, and during this time the SO has improved competition by allowing multiple Frequency Keepers of smaller size to participate. The main area of concern around Normal Frequency management has been the lack of clarity in the Electricity Industry Participation Code (EIPC) requirements for generator governors. The rules provide room for generators to either obtain an exemption with little consequence, or have a large deadband in the frequency response. A recent consultation by the Electricity Authority (Electricity Authority, 2017) aims to either allow the current situation to be codified, or the generators providing a significant service to be remunerated.

How contingent events are managed has seen significant development in recent years, both in the AUFLS scheme, and the combining of North Island and South Island IR markets. These changes have reduced requirements for IR and increased competition in its supply. Looking past these recent developments there has been further interest in IR, particularly in wind generation offering reserves, and other new products or methodologies. One TASC report, New IR Products (System Operator, 2015), has analysed several options, providing a list of ideas that should be developed further. The recommendations of the report move away from defining new products, as has been the response of Ireland, but to develop a mechanism to value the total response of the service providers, particularly the idea of Area under the Curve (AUTC) suggested by Roger Miller. Further recommendations were made around the definition of FIR and SIR – the details can be found in (System Operator, 2015).

8.5. Requirements for Ancillary Services with Increasing Wind Penetrations

In this section, the results of GREEN Grid research, with regard to implications for the need for frequency control ancillary services, are summarised. Firstly, the demand for ancillary service types is summarised from previous sections of the report, and in light of the discussion above, four recommendations are made for the development of the New Zealand AS markets.

8.5.1. Summary of Impacts on Ancillary Service Requirements

Ramping Reserve

Ramping reserve refers to reserve held to follow large sustained changes in demand and wind power output, and is primarily required for systems which are predominately thermal based. This is not necessary for New Zealand given New Zealand's large hydro resource, which can provide fast ramping capacity through the dispatch process.

Tertiary Reserve

Tertiary Reserve holds thermal generation with long start up times in a state of readiness. The high energy and Instantaneous Reserve price events of 2014 and 2016 could have been mitigated by a Tertiary Reserves market to incentivise generation plant like Taranaki Combined Cycle to remain online and provide energy and Instantaneous Reserve capacity. In a near 100% renewable energy generation scenario, the results from Section 4.2.1 suggest that starting and stopping is going to become more frequent. This implies Tertiary Reserves market should be considered, but there has been no analysis in this work considering thermal power station start up times and wind generation forecasting accuracy at the half a day to a day time horizons, in order to properly assess the requirement for a Tertiary Reserves market. It is expected that larger geothermal and wind generation penetrations will result in the exit of base-load thermal plant with long start-up times from the market. As a result of the withdrawal of base-load thermal plant, fast start open cycle plant may enter the market to provide capacity during energy shortages, such as low wind generation or low hydro levels. Hence the requirements for Tertiary Reserves is not expected to remain, assuming open cycle peaking gas turbines that enter the market have sufficiently rapid start up times.

Frequency Keeping

Demand for FK (discussed in Section 2.3.2) is expected to increase by 40 MW for an increase of 4000 MW of wind generation, as shown in Section 6.3. Currently 30 MW is procured, therefore the total requirement should not be more than 70 MW. This is less than the historical FK requirement of 125 MW, which was been met by generation offered FK Reserve in the past.

Droop

Droop was introduced in Section 2.3.1, and refers to the governor response of generators that increases output as system frequency falls or decreases output as system frequency increases. Droop is currently not an ancillary service, but its provision is mandatory. Requirements for it are expected to increase by 42 %, as shown in Section 6.3. Droop is expected to remain with Hydro Generation; however, periods of low demand and high variable renewable generation will require more droop response from those few hydro stations still connected. Due to this concentration of droop provision amongst few generators, it is recommended that droop become an Ancillary Service and a market established, ensuring sufficient droop response during lightly loaded conditions.

Instantaneous Reserve

Overall requirements for IR may decrease as large CCGTs may only run 20 to 40% of the time under high wind penetration, or not at all as New Zealand approaches 100% renewable generation. However, it will be punctuated by periods of higher IR requirements when the HVDC link operates at high power transfers. The reduction in inertia will result in a greater requirement for FIR in the North Island during high HVDC power transfer.

Automatic Under-Frequency Load-Shedding

In order to keep the power system stable after a bipole trip of the HVDC link, it may be necessary to acquire more AUFLS to reduce the requirement for Instantaneous Reserve. Therefore, it is recommended that size of AUFLS bands be increased or the number of bands be increased.

Inertia

As shown in Section 5.1 and Appendix F, inertia will decrease as wind generation increases. Inertia is crucial to the stable operation of the power system, and its reduction will require an increase in FIR in order to halt increasingly rapid changes in system frequency under contingencies. Hence an ancillary service to gain more inertia in the grid may be of value. Also shown in Appendix E, energy curtailment, or spill, will occur more often under high wind generation scenarios. If an inertia AS existed, the need for FIR might be reduced. However, retaining sufficient inertia is recommended to be achieved through the must-run auction, this idea is developed in Section 9.

8.5.2. Proposed Ancillary Service Changes

1. Normal Frequency Management

For Normal Frequency Management with increased variable renewable generation the most important issues are: (1) ensuring enough droop during low demand periods; (2) keeping droop an energy neutral process, i.e. on average not changing the generation dispatch; and (3) making sure minimal energy resources are used when providing droop. The second point is concerned with minimising interference with the energy market. If a provider is committed to supplying a quantity of energy this should not be changed by Droop responding to bias in the power imbalance. The third point assumes for some providers of Droop it has an energy cost, e.g. energy storage has a cycling inefficiency, or to increase droop from a hydro power station instead of running one turbine at full output, run two turbines at half output at the cost of running less efficiently. The extra energy required in providing Droop does not need to be accounted for in the energy market, but can be reflected in the price of providing it.

Droop availability is fundamentally tied to the energy market because demand determines the number of generators dispatched (fewer generators dispatched means less droop and vice versa). It is proposed that there be a combined droop and FK market, called the Normal Frequency Market (NFM), the features of the market are:

- Dispatch NFM after the energy market, so that the energy market has primacy and is not unduly influenced by the normal frequency market. Co-optimization is not required as capacity for NFM reserve is relatively small, and is over shadowed by the IR market. Also the NFM is most necessary during low demand periods, where there is plenty of capacity available.
- The requirement for NFM reserve will be determined by a target in the frequency quality, e.g. frequency is only allowed to deviate once in three hours outside 49.8 to 50.2 Hz band. The

definition of the standard should retain the separation of control strategies for normal changes and large contingencies.

- Participants' offers are composed of deadband, droop characteristic, and price, as well as FK Offers. Those generators dispatched for Droop will be required to turn it on, while other generators may turn it off. This should allow the cost of Droop to be compensated based on generators' costs of providing it (primarily increased maintenance costs as well as reduced operational efficiency).
- Price will be in terms of MW mileage, instead of a capacity based price. Mileage is the total movement in power output up and down, and is supposed to reflect the effort of response. The precise definition of mileage requires standardisation to ensure fair charging and compensation.
- The definition of the NFM reserve product should allow for the entry of non-conventional forms of droop response, such as energy storage (batteries, hot water heaters, etc.) and load aggregation including electric vehicles. Whether these new resources will be used is determined if they are cost competitive against the large availability of hydro generation.

It is anticipated that most of the time there will be an abundance of droop resource, but the situation will become critical during low periods of energy demand and high wind. Backing the droop market will be the need for appropriate cost allocation, to ensure collection of the costs of providing droop from, ideally, those that give rise to it. Those parties will be demand, initially, but later wind generation as it increases. In this way there may be incentives to reduce variability by both demand and wind generation, which may be sufficient for frequency response load devices to be deployed without direct compensation.

2. *Contingency Event Management*

In contingency management, the most important issues are: (1) ensuring enough capacity is available to respond to contingencies; and (2) determining when to reduce the largest risk. The results from Section 6.1.3 show that there is potential from the HVDC pole risk for a large requirement of FIR as higher HVDC transfer is coupled with lower inertia in the North Island. The 26th July 2016 event, Section 7.2, has shown the potential for inadequate capacity as the system nears the energy and reserve capacity constraints. The HVDC link is a supply for North Island demand, but when transfer is constrained against NI IR availability, its ability to supply the NI energy demand is restricted. If HVDC transfer were reduced, thereby decreasing risk, then this will not give the overall relief in the capacity constraint, as the power requirement will increase for North Island generation. The result of changing the HVDC transfer is only to exchange between energy and reserve requirements in the NI. Therefore point two above is less pertinent. The critical issue is ensuring sufficient capacity investment, as mentioned in Section 8.2. This section does not provide recommendations for improving capacity investment in general, but focusses on capacity for reserves. The recommendation is to develop the IR market to modify the definition of FIR and by doing so incentivise faster speed of response.

It has been shown in the analysis of Section 3.2 and Section 6.1.3 that fast Rate of Change of Frequency (RoCoF) requires more reserve than the risk of the event. That is more units offering spinning reserve with headroom are required in order to increase the initial speed of response, even though all that headroom may not be required. This is especially applicable for large events where the minimum frequency is reached before 6 seconds. The better practice is to incentivise faster types of reserve, such as Interruptible Load and power electronic converter types of reserve initially, and then use spinning reserve when the fast types of reserve can longer sustain the output. Overall less headroom is required from spinning reserve providers, thereby freeing capacity for energy requirements.

For the current formulation of the Instantaneous Reserve market there is no mechanism to value speed of response as well as capacity. To value speed of response requires consideration of the response curve of the provider over time. From Eq. 3.1, the derivative of the frequency is proportional to the power imbalance between electrical demand and mechanical power supplied, therefore taking the integral of the response curve provides the trajectory of the grid frequency. If the frequency is constrained to be above 48 Hz, then the providers can be optimized. The process of calculating the integral gives the name for these types of formulations, i.e. Area under the Curve (AUTC). To incentivise faster speed of response, different responses will have to have different prices, instead of having a single price determined by the marginal value of risk.

3. AUFLS Block Size

In order to manage the contingency of a large bipole trip of the HVDC link, it is recommended to reconsider the size of AUFLS blocks so that the transfer limit can be increased. This allows greater utilisation of spatial diversity of wind farms between the North Island and South Island, and therefore minimise curtailed wind generation.

9. Further Research

To progress renewable energy development in New Zealand, this research suggests further study around the design of the must-run and energy markets.

1. *Must Run Market*

Following the discussion in Section 8.2 on energy market considerations, it is anticipated that in reaching 100% renewable electricity generation, without significant addition of energy storage – comparable or greater in size to our current hydro storage – that some renewable energy will be curtailed. Therefore, to maintain the security of the power system, a mechanism is required in the must-run auction to dispatch inertia, to ensure that inertia based generation is dispatched in preference to inertialess generation.

The must-run auction, as defined in clauses 13.107 to 13.130 of the EIPC, is used for periods of low demand and high must-run generation, e.g. Christmas. The must-run auction allows generators who have to generate electricity to pay a premium to run. This effectively allows for negative electricity prices in the New Zealand Electricity Market, which cannot be obtained through SPD. Although rarely fully utilised, it is expected that the must-run market will be more critical under high penetration of wind generation. Therefore to increase system security, hydro generation should have a preference over wind generation.

To develop the must run market requires ground work to understand the necessary mathematical underpinning of hydro storage and wind generation risk management, i.e. when is it the best practice to start curtailing wind generation as hydro storage levels increase to both avoid spilling hydro generation, and maintain system inertia.

2. *Energy Market*

As more variable renewable generation is added to the New Zealand electricity system to increase renewable penetration, two problems arise: wind generation is curtailed in periods of excess must-run generation, the value of wind generated energy decreases even before it is spilled, reducing the incentive to further invest in wind generation; and thermal is still required to balance periods of no wind generation, but those periods are smaller, meaning there is concern whether there is enough incentive to retain peaking plant. The power system is going to cost more for a higher renewable penetration. Assuming the electricity market ideally finds the optimal long term generation portfolio for New Zealand, it appears approaching 100% renewable energy is not possible without changes to the energy market. It is recommended that research into how revenues flow to different energy types be conducted, in order to understand how value is given to energy storage size, capacity, etc. Therefore it may be possible to understand how wind generation and peaking capacity should be incentivised to optimize both economic and environmental costs.

3. *The Relationship between Spatial Diversity of Wind Farms, Wind Curtailment, and HVDC Transfer Capability*

Since HVDC transfer capacity is largely constrained by North Island IR availability, it would be of interest to understand the value of increasing HVDC transfer capacity by increasing the proportion of demand in the AUFLS scheme, or by procuring more IR. The value of increasing the HVDC capacity is by allowing more wind generation in the South Island to displace thermal generation in the North Island, giving a higher net transfer north. The value of having wind generation in the South Island is the benefit from spatial diversification of wind farms, creating a more consistent supply of wind generation with higher troughs and lower peaks, thereby minimizing the demand for peaking generation, and the curtailment of wind generation when there is too much must-run generation. The month of June 2017 demonstrated this, where South Island wind generation remained at high output, while North Island wind generation spent substantial periods generating at very low output compared to its capacity.

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A. Minimum Frequency for Contingent Event

Section 3.2 introduces Eq. 3.5 for the minimum frequency during a contingent event. This appendix derives that equation. The parameters of the equation are defined from the power system, Figure 3.1, and the generation imbalance, Figure 3.2. To find the minimum frequency the frequency signal is solved first, which requires the solving of a differential equation. The differential equation is derived in reverse from the transfer function of the control block diagram, Figure 3.1:

$$\Delta f(s) = \frac{1}{2Hs}\left(\Delta P_M(s) - \Delta P_E(s) - D\Delta f(s)\right) \qquad (A.1)$$

where all quantities are in per unit. Δf is the perturbation in frequency from the 50 Hz, the base quantity, f_b is 50 Hz. The mechanical power, ΔP_M, and electrical power, ΔP_E, have a base quantity, P_b, of 3000 MW. H is inertia and D is load damping. For a contingent event the electrical power is constant, $\Delta P_E(s) = 0$. Rearranging Eq. A.1 to have frequency on one side of the equation:

$$2Hs\Delta f(s) + D\Delta f(s) = \Delta P_M(s) \qquad (A.2)$$

Converting from the s-domain to the time domain:

$$2H\frac{d\Delta f(t)}{dt} + D\Delta f(t) = \Delta P_M(t) \qquad (A.3)$$

Dividing both sides by $2H$, τ_c is defined as $2H/D$:

$$\frac{d\Delta f(t)}{dt} + \frac{1}{\tau_c}\Delta f(t) = \frac{\Delta P_M(t)}{2H} \qquad (A.4)$$

Multiplying both sides of the equation by e^{t/τ_c}, grid frequency is simplified by the product rule:

$$\frac{d}{dt}\left(e^{t/\tau_c}\Delta f(t)\right) = e^{t/\tau_c}\frac{\Delta P_M(t)}{2H} \qquad (A.5)$$

Setting the initial frequency to zero, $f(0) = 0$, the frequency signal is:

$$\Delta f(t) = \frac{1}{2H}e^{-t/\tau_c}\int_0^t e^{\tau/\tau_c}\,\Delta P_M(\tau)d\tau \qquad (A.6)$$

Therefore, the solution for the frequency signal is the completion of an integral. For simplicity in the working, signal $q(t)$ is defined:

$$q(t) = \int_0^t e^{\tau/\tau_c}\,\Delta P_M(\tau)d\tau \qquad (A.7)$$

To solve for $q(t)$, $\Delta P_M(\tau)$ requires definition, Figure A.1:

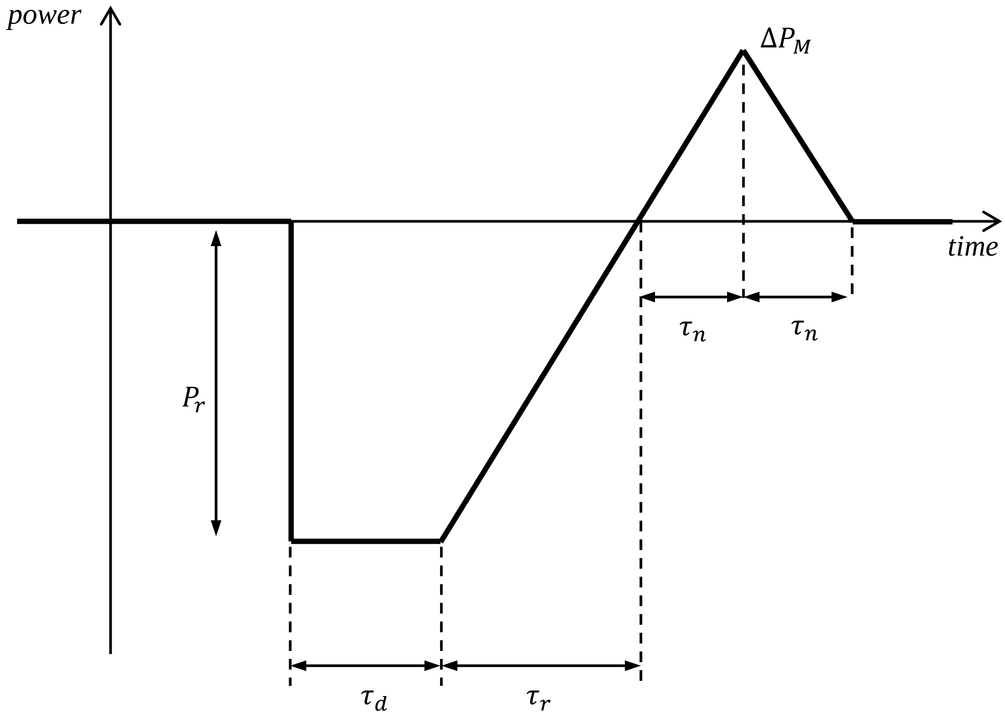

Figure A.1: Combined turbine mechanical power during a loss of generation. This figure also defines the parameters P_r, the lost generation (pu); τ_d, the delay time to respond (s); and τ_r, the time to respond in equal magnitude to the lost generation. τ_n is half the over shoot time required to return the frequency to 50 Hz.

$$\Delta P_M(t) = \begin{cases} -P_r & 0 \le t < \tau_d \\ \dfrac{P_r}{\tau_r}\big(t - (\tau_d + \tau_r)\big) & \tau_d \le t < \tau_d + \tau_r + \tau_n \\ -\dfrac{P_r}{\tau_r}\big(t - (\tau_d + \tau_r + 2\tau_n)\big) & \tau_d + \tau_r + \tau_n \le t < \tau_d + \tau_r + 2\tau_n \end{cases} \quad (A.8)$$

For simplicity, $\tau_1 = \tau_d + \tau_r$, and $\tau_2 = \tau_d + \tau_r + 2\tau_n$:

$$\Delta P_M(t) = \begin{cases} -P_r & 0 \le t < \tau_d \\ \dfrac{P_r}{\tau_r}(t - \tau_1) & \tau_d \le t < \tau_1 + \tau_n \\ -\dfrac{P_r}{\tau_r}(t - \tau_2) & \tau_1 + \tau_n \le t < \tau_2 \end{cases} \quad (A.9)$$

Therefore, solving the integral is separated by time interval, $0 \le t < \tau_d$:

$$q_1(t) = \int_0^t -P_r e^{\tau/\tau_c}\, d\tau = P_r \tau_c \left(1 - e^{t/\tau_c}\right) \quad (A.10)$$

For $\tau_d \le t < \tau_1 + \tau_n$:

$$q_2(t) = \int_{\tau_d}^{t} \frac{P_r}{\tau_r}(t - \tau_1) e^{\tau/\tau_c}\, d\tau + q_1(\tau_d) = P_r \tau_c \left(1 + \frac{t - \tau_1 - \tau_c}{\tau_r} e^{t/\tau_c} + \frac{\tau_c}{\tau_r} e^{\tau_d/\tau_c}\right) \quad (A.11)$$

For $\tau_1 + \tau_n \leq t < \tau_2$:

$$q_3(t) = \int_{\tau_d}^{t} -\frac{P_r}{\tau_r}(t-\tau_2)e^{\tau/\tau_c}\,d\tau + q_2(\tau_1+\tau_n) \qquad (A.12a)$$

$$= P_r\tau_c\left(1 - \frac{t-\tau_2-\tau_c}{\tau_r}e^{t/\tau_c} - \frac{2\tau_c}{\tau_r}e^{\frac{\tau_1+\tau_n}{\tau_c}} + \frac{\tau_c}{\tau_r}e^{\tau_d/\tau_c}\right) \qquad (A.12b)$$

Therefore

$$q(t) = \begin{cases} q_1(t) & 0 \leq t < \tau_d \\ q_2(t) & \tau_d \leq t < \tau_1 + \tau_n \\ q_3(t) & \tau_1 + \tau_n \leq t < \tau_2 \end{cases} \qquad (A.13)$$

The solution for $\Delta f(t)$ is:

$$= \frac{P_r\tau_c}{2H}\begin{cases} e^{-t/\tau_c} - 1 & 0 \leq t < \tau_d \\ e^{-t/\tau_c} + \dfrac{t-\tau_1-\tau_c}{\tau_r} + \dfrac{\tau_c}{\tau_r}e^{-(t-\tau_d)/\tau_c} & \tau_d \leq t < \tau_1 + \tau_n \\ e^{-t/\tau_c} - \dfrac{t-\tau_2-\tau_c}{\tau_r} + \dfrac{\tau_c}{\tau_r}e^{-(t-\tau_d)/\tau_c} - \dfrac{2\tau_c}{\tau_r}e^{\frac{-(t-(\tau_1+\tau_n))}{\tau_c}} & \tau_1 + \tau_n \leq t < \tau_2 \end{cases} \qquad (A.14)$$

For completeness it is desirable that $\Delta f(\tau_2) = 0$, so that the frequency returns to its original value. To retain the independence of τ_d and τ_r, τ_n is uniquely determined:

$$\tau_n = -\tau_c \ln\left(\frac{1-\sqrt{1-A}}{A}\right) \quad where \;\; A = \frac{\tau_r}{\tau_c}e^{-\frac{\tau_d+\tau_r}{\tau_c}} + e^{-\frac{\tau_r}{\tau_c}} \qquad (A.15)$$

The minimum frequency of $\Delta f(t)$ is derived by taking the derivative, and finding the time it equals zero; since it is noticed that the minimum frequency is always in the second time interval, differentiation is limited to the second interval, $\tau_d \leq t < \tau_1 + \tau_n$:

$$0 = \frac{d\Delta f(t)}{dt} = \frac{P_r\tau_c}{2H}\left(-\frac{1}{\tau_c}e^{-t/\tau_c} + \frac{1}{\tau_r} - \frac{1}{\tau_r}e^{-(t-\tau_d)/\tau_c}\right) \qquad (A.16)$$

The time of the minimum frequency, t_{min}, is:

$$t_{min} = -\tau_c \ln\left(\frac{\tau_c}{\tau_r + \tau_c e^{\tau_d/\tau_c}}\right) \qquad (A.17)$$

Substituting t_{min} into $\Delta f(t)$:

$$\Delta f_{min} = -\frac{P_r\tau_c}{2H\tau_r}\left(\tau_c \ln\left(\frac{\tau_c}{\tau_r + \tau_c e^{\tau_d/\tau_c}}\right) + \tau_d + \tau_r\right) \qquad (A.18)$$

Converting from the per unit perturbation from the nominal frequency to the actual frequency:

$$f_{min} = f_b - \frac{P_r\tau_c f_b}{2H\tau_r}\left(\tau_c \ln\left(\frac{\tau_c}{\tau_r + \tau_c e^{\tau_d/\tau_c}}\right) + \tau_d + \tau_r\right) \qquad (A.19)$$

A.1. Minimum Event Frequency with Load Shedding

The previous section defined the response of the power system to a loss of generation and the response of other generation to remove the imbalance. This section determines the response of the power system with emergency load shedding, whether that it is through Interruptible Load (IL) or through Automatic Under-Frequency Load Shedding (AUFLS). The power balance of the generators and load shedding is:

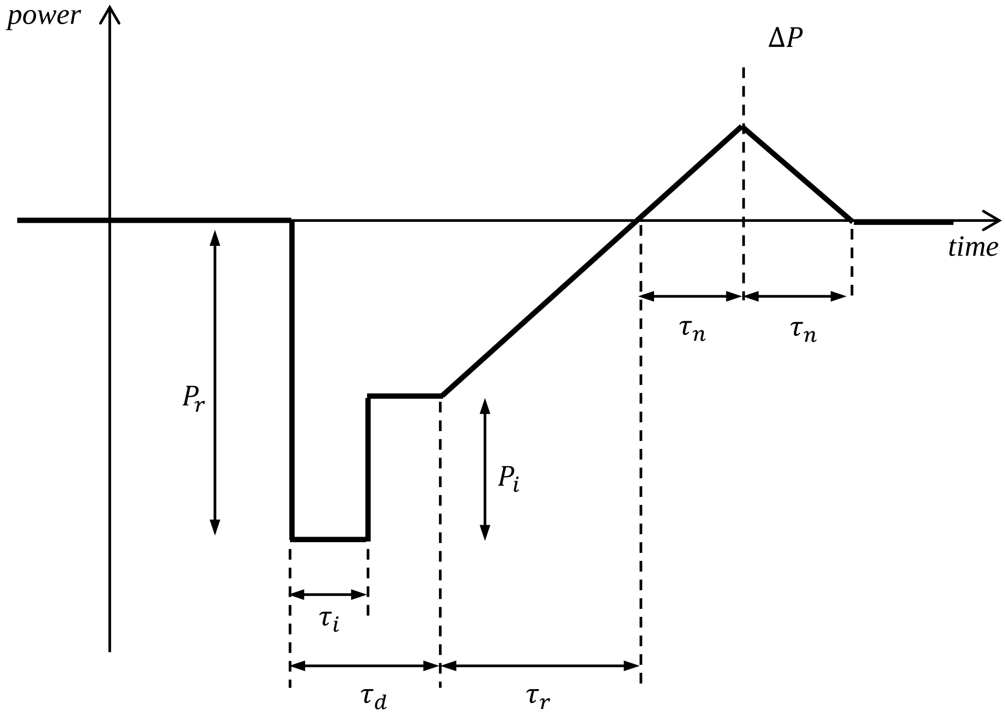

Figure A.2: Combined turbine mechanical power during a loss of generation, and the emergency loss of load. This figure also defines the parameters P_r, the lost generation (pu); P_i, the lost demand from emergency shedding; τ_i, the time for emergency shedding respond; τ_d, the delay time to respond (s); and τ_r, the time to respond in equal magnitude to the lost generation. τ_n is half the over shoot time required to return the frequency to 50 Hz. This figure shows $\tau_i < \tau_d$, but τ_i can be longer than τ_d.

The power system frequency is found by separating the signal of Figure A.2 into step and ramp functions and finding the response for each component separately. The generic step and ramp functions are described in Figure A.3 and A.4, respectively.

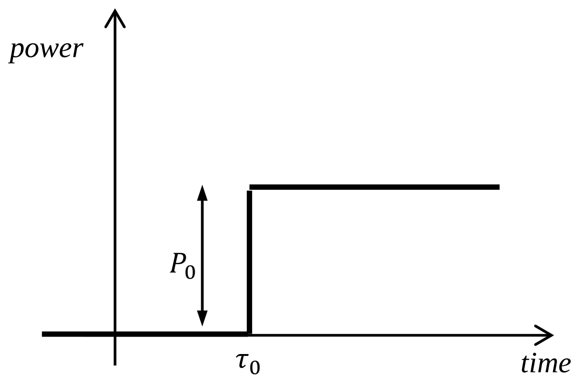

Figure A.3: Definition of the step function.

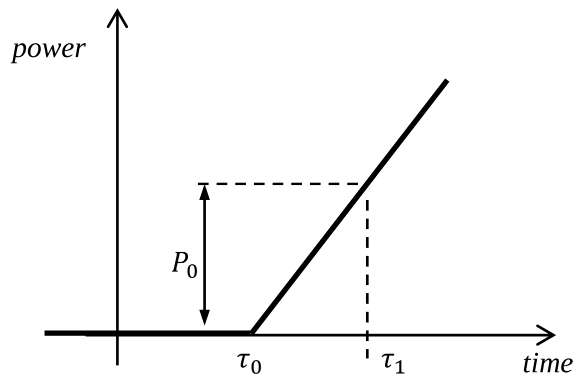

Figure A.4: Definition of the ramp function.

The grid frequency response for the step function is:

$$f_{step}(t) = \begin{cases} 0 & t < \tau_0 \\ \frac{P_0 \tau_c}{2H}\left(1 - e^{-\frac{t-\tau_0}{\tau_c}}\right) & t \geq \tau_0 \end{cases} \qquad (A.20)$$

The grid frequency response for the ramp function is:

$$f_{ramp}(t) = \begin{cases} 0 & t < \tau_0 \\ \frac{P_0 \tau_c}{2H(\tau_1 - \tau_0)}\left(t - \tau_c - \tau_0 + \tau_c e^{-\frac{t-\tau_0}{\tau_c}}\right) & t \geq \tau_0 \end{cases} \qquad (A.21)$$

The function of Figure A.2 can be separated into four signals:

Table A.1: Separation of the power balance of Figure A.2.

Component	Type	P_0	τ_0	τ_1
1	Step	$-P_r$	0	-
2	Step	P_i	τ_s	-
3	Ramp	$P_r - P_i$	τ_d	$\tau_d + \tau_r$
4	Ramp	$-2(P_r - P_i)$	$\tau_d + \tau_r + \tau_n$	$\tau_d + 2\tau_r + \tau_n$

The resultant four grid frequency responses in per unit deviation from 50 Hz is:

$$\Delta f_1(t) = \begin{cases} 0 & t < 0 \\ \frac{-P_r \tau_c}{2H}\left(1 - e^{-\frac{t}{\tau_c}}\right) & t \geq 0 \end{cases} \qquad (A.22a)$$

$$\Delta f_2(t) = \begin{cases} 0 & t < \tau_s \\ \frac{P_i \tau_c}{2H}\left(1 - e^{-\frac{t-\tau_s}{\tau_c}}\right) & t \geq \tau_s \end{cases} \qquad (A.22b)$$

$$\Delta f_3(t) = \begin{cases} 0 & t < \tau_d \\ \frac{(P_r - P_i)\tau_c}{2H\tau_r}\left(t - \tau_c - \tau_d + \tau_c e^{-\frac{t-\tau_d}{\tau_c}}\right) & t \geq \tau_d \end{cases} \qquad (A.22c)$$

$$\Delta f_4(t) = \begin{cases} 0 & t < \tau_2 \\ \frac{-2(P_r - P_i)\tau_c}{2H\tau_r}\left(t - \tau_c - \tau_2 + e^{-\frac{t-\tau_2}{\tau_c}}\right) & t \geq \tau_2 \end{cases} \qquad (A.22d)$$

where $\tau_2 = \tau_d + \tau_r + \tau_n$. Therefore, the complete grid frequency is:

$$\Delta f(t) = \Delta f_1(t) + \Delta f_2(t) + \Delta f_3(t) + \Delta f_4(t) \qquad (A.23)$$

For the purposes of completeness τ_n is defined so that $\Delta f(\tau_d + \tau_r + 2\tau_n) = 0$. The solution for τ_n is:

$$\tau_n = -\tau_c \ln\left(\frac{1 - \sqrt{1 - A}}{A}\right) \quad where \;\; A = \beta \frac{\tau_r}{\tau_c} e^{-\frac{\tau_d + \tau_r}{\tau_c}} + e^{-\frac{\tau_r}{\tau_c}}, \;\; \beta = \frac{P_r - P_i e^{\frac{\tau_s}{\tau_c}}}{P_r - P_i} \qquad (A.24)$$

The point of interest is when the grid frequency reaches its minimum, the equation for the minimum frequency depends on parameters of the response. However, the most important situation is where both load shedding and generator response is required to rest the fall in frequency. This implies $P_i < P_r$, and $t_{min} > \tau_d$ and $t_{min} > \tau_s$. Therefore, in order to find the time in which the minimum frequency is reached, the first three terms of Eq. A.23 are differentiated and set to zero:

$$t_{min} = -\tau_c \ln\left(\frac{\tau_c}{\tau_r\beta + \tau_c e^{\tau_d/\tau_c}}\right) \quad where \quad \beta = \frac{P_r - P_i e^{\frac{\tau_s}{\tau_c}}}{P_r - P_i} \qquad (A.25)$$

The minimum frequency is:

$$\Delta f_{min} = -\frac{(P_r - P_i)\tau_c}{2H\tau_r}\left(\tau_c \ln\left(\frac{\tau_c}{\tau_r\beta + \tau_c e^{\tau_d/\tau_c}}\right) + \tau_d + \tau_r\right) \qquad (A.26)$$

$$f_{min} = f_b - \frac{(P_r - P_i)\tau_c f_b}{2H\tau_r}\left(\tau_c \ln\left(\frac{\tau_c}{\tau_r\beta + \tau_c e^{\tau_d/\tau_c}}\right) + \tau_d + \tau_r\right) \qquad (A.27)$$

which is noticeably similar to Eq. A.18 and A.19. Following a similar approach to Section 3.2, it is important to analyse how load shedding improves the required response time of the remaining generators by reducing the speed requirements. A scenario is chosen where half of the reserve is provided by Interruptible Load, i.e. $P_i = 0.5P_r$, hence Eq. A.27 becomes:

$$f_{min} = f_b - \frac{P_r\tau_c f_b}{4H\tau_r}\left(\tau_c \ln\left(\frac{\tau_c}{\tau_r\beta + \tau_c e^{\tau_d/\tau_c}}\right) + \tau_d + \tau_r\right) \qquad (A.28)$$

Defining the uncontrolled time to reach 48 Hz by Eq. 3.9 and 3.4, then substitute into Eq. A.28:

$$\tau_m = \frac{\tau_c}{2\tau_r}\left(\tau_c \ln\left(\frac{\tau_c}{\tau_r\beta + \tau_c e^{\tau_d/\tau_c}}\right) + \tau_d + \tau_r\right) \qquad (A.29)$$

Therefore, it is left to define the time, τ_s, when interruptible load trips. In the New Zealand power system, Interruptible Load operates after the frequency has dropped below 49.2 Hz plus a delay to initiate the circuit breaker, which is roughly 0.3 seconds:

$$\tau_s = t_{49.2} + 0.3 \qquad (A.30)$$

The formula for $t_{49.2}$ is dependent on $\tau_c,\ \tau_d,\ \tau_r$, and τ_m, and requires numerically solving, so no closed form equation describes the relationship between τ_r and τ_m with IL. An iterative approach is used to determine the relationship. A comparison of the results is shown in Figure A.5. It is evident that IL has significant benefit, as for the same event the required time for generation respond becomes a half order of magnitude longer. Instead of analysing the system by the required response time, for an event it can be compared against the required ramp rate, Figure A.6, and required amount of 6 second Fast Instantaneous Reserve (FIR), Figure A.7.

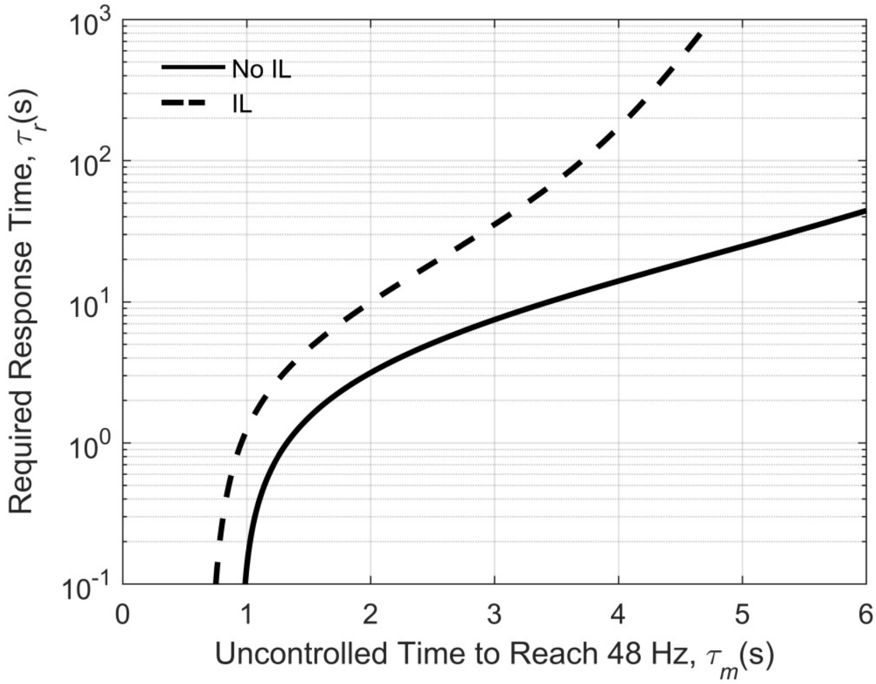

Figure A.5: Comparison of required response times for IL based provision of reserve and provision from just generation.

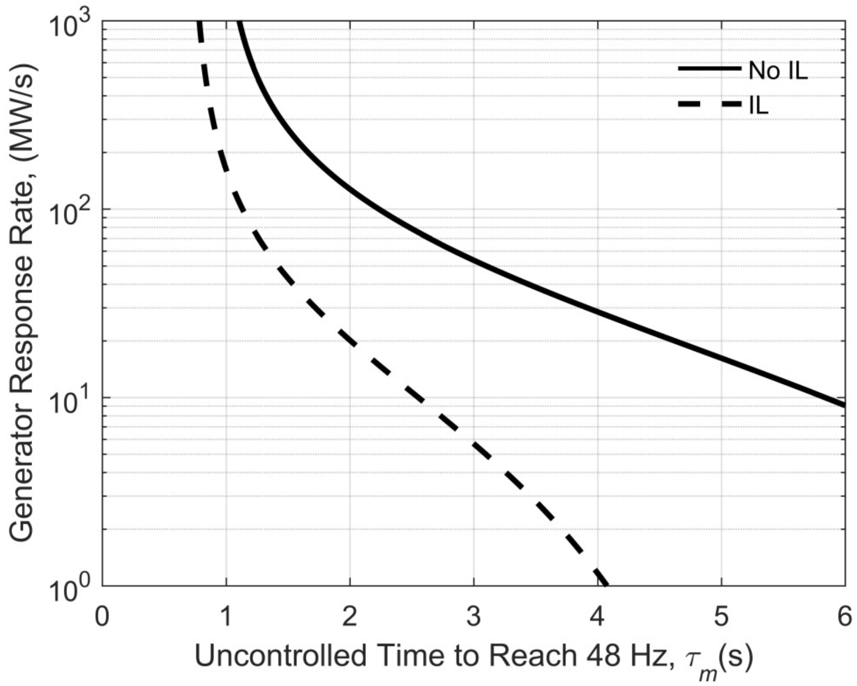

Figure A.6: Comparison of reserve provision mechanisms by the required ramp rate.

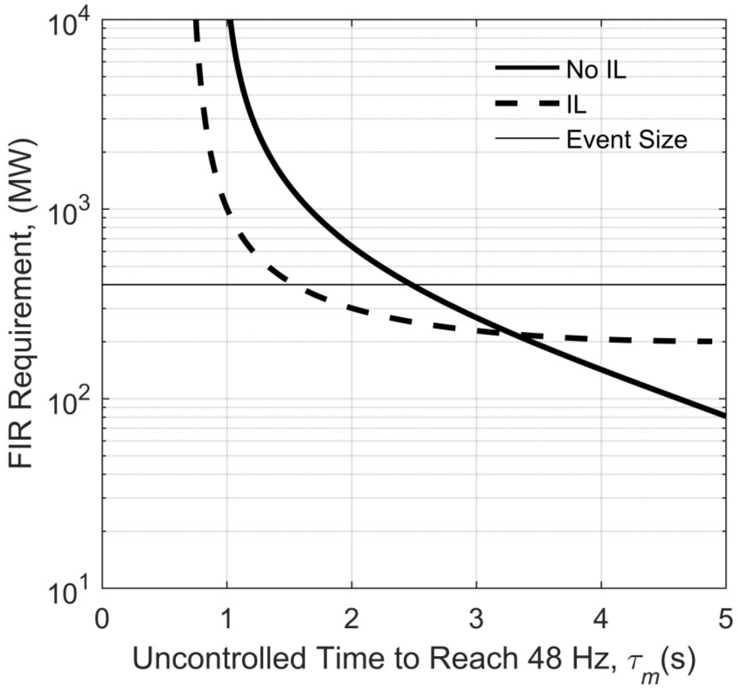

Figure A.7: Demand for FIR depending on how quickly the grid frequency approaches 48 Hz, τ_m.

B. The Peak in the Controlled Frequency Response

In Section 3.3, Eq. 3.15 provides the decomposition frequency of the maximum response of the power system, Eq. 3.14 and Figure 3.7. This appendix provides a derivation of that minimum frequency, and its approximation. The peak gain is also derived; however, it was not presented in the body of the report. In order to determine the decomposition frequency of the peak gain, the gain of the transfer function is required first:

$$|G_2(j\omega)| = \sqrt{G_2(j\omega)G_2^*(j\omega)} \qquad (B.1)$$

The asterisk refers to the complex conjugate. Before Eq. B.1 is derived explicitly, Eq. 3.14 is expanded and simplified, and put into canonical form:

$$G_2(s) = \frac{\tau_g s + 1}{2H\tau_g s^2 + \left(2H + D\tau_g\right)s + D + R} \qquad (B.2a)$$

$$G_2(s) = \frac{1}{D+R}\frac{1 + \tau_g s}{1 + \frac{2H + D\tau_g}{D+R}s + \frac{2H\tau_g}{D+R}s^2} \qquad (B.2b)$$

$$G_2(s) = K\frac{1 + \beta_1 s}{1 + \alpha_1 s + \alpha_2 s^2} \qquad (B.2c)$$

where

$$K = \frac{1}{D+R} \qquad (B.3a)$$

$$\beta_1 = \tau_g \qquad (B.3b)$$

$$\alpha_1 = \frac{2H + D\tau_g}{D+R} \qquad (B.3c)$$

$$\alpha_2 = \frac{2H\tau_g}{D+R} \qquad (B.3d)$$

Solving Eq. B.1:

$$|G_2(j\omega)| = K\frac{\sqrt{1 + \beta_1^2\omega^2}}{\sqrt{1 + (\alpha_1^2 - 2\alpha_2)\omega^2 + \alpha_2^2\omega^4}} \qquad (B.4)$$

Simplifying by making $\omega^2 = x$:

$$\left|G_2\left(j\sqrt{x}\right)\right| = K\frac{\sqrt{1 + \beta_1^2 x}}{\sqrt{1 + (\alpha_1^2 - 2\alpha_2)x + \alpha_2^2 x^2}} \qquad (B.5)$$

The numerator and the denominator are simplified, for the differentiation step:

$$\left|G_2\left(j\sqrt{x}\right)\right| = K\frac{\sqrt{\sigma_n(x)}}{\sqrt{\sigma_d(x)}} \qquad (B.6)$$

$$\frac{d\left|G_2\left(j\sqrt{x}\right)\right|}{dx} = \frac{K}{2}\frac{\sqrt{\sigma_d(x)}}{\sqrt{\sigma_n(x)}}\frac{\sigma_n'(x)\sigma_d(x) - \sigma_d'(x)\sigma_n(x)}{\sigma_d^2(x)} \qquad (B.7)$$

where $\sigma_n'(x) = \beta_1^2$, and $\sigma_d'(x) = 2\alpha_2^2 x + \alpha_1^2 - 2\alpha_2$. For the derivative to equal zero it is necessary that:

$$\sigma_n'(x)\sigma_d(x) - \sigma_d'(x)\sigma_n(x) = 0 \qquad (B.8)$$

Expanding Eq. B.8:

$$2\alpha_2^2\beta_1^2x^2 + 2\alpha_2^2x + (\alpha_1^2 - 2\alpha_2 - \beta_1^2) = 0 \qquad (B.9)$$

The desired solution for x and consequently for ω is:

$$x = \frac{1}{\beta_1^2}\left(-1 + \sqrt{1 - \frac{\beta_1^2}{\alpha_2^2}(\alpha_1^2 - 2\alpha_2 - \beta_1^2)}\right) \qquad (B.10)$$

$$\omega = \frac{1}{\beta_1}\sqrt{-1 + \sqrt{1 - \frac{\beta_1^2}{\alpha_2^2}(\alpha_1^2 - 2\alpha_2 - \beta_1^2)}} \qquad (B.11)$$

Substituting in Eqs. B.3:

$$\omega_{max} = \frac{1}{\tau_g}\sqrt{-1 + \frac{1}{2H}\sqrt{\tau_g R\left(4H + \tau_g R + 2D\right)}} \qquad (B.12)$$

The maximum frequency is obtained by dividing by 2π:

$$f_{max} = \frac{1}{2\pi\tau_g}\sqrt{-1 + \frac{1}{2H}\sqrt{\tau_g R\left(4H + \tau_g R + 2D\right)}} \qquad (B.13)$$

To determine the gain at this frequency Eq. B.10 is substituted into Eq. B.5:

$$|G_2(j\omega_{max})| = \frac{K\beta_1^2}{\sqrt{\alpha_1^2\beta_1^2 - 2\alpha_2^2 - 2\alpha_2\beta_1^2 + 2\alpha_2^2\sqrt{1 - \frac{\beta_1^2}{\alpha_2^2}(\alpha_1^2 - 2\alpha_2 - \beta_1^2)}}} \qquad (B.14)$$

Substituting in Eqs. B.3:

$$|G_2(j\omega_{max})| = \frac{\tau_g}{\sqrt{D^2\tau_g^2 - 4H^2 - 4H\tau_g R + 4H\sqrt{\tau_g R\left(4H + \tau_g R + 2D\right)}}} \qquad (B.15)$$

To approximate the decomposition frequency of the peak gain, and the peak gain itself, it is helpful to consider that:

$$\tau_g R \gg 4H + 2D \qquad (B.16)$$

For the values of $\tau_g = 80\ s$, $R = 28$, $H = 23/3$, and $D = 5/3$, Eq. B.16 becomes:

$$80 \times 28 \gg 4 \times \frac{23}{3} + 2 \times \frac{5}{3}, \qquad 2240 \gg 34 \qquad (B.17)$$

Therefore Eq. B.13 simplifies to give an approximation of the peak frequency:

$$f_{max} \approx \frac{1}{2\pi\tau_g}\sqrt{-1 + \frac{\tau_g R}{2H}} = \frac{1}{2\pi\tau_g}\sqrt{\frac{\tau_g R - 2H}{2H}} \qquad (B.18a)$$

$$f_{max} \approx \frac{1}{2\pi\tau_g}\sqrt{\frac{\tau_g R}{2H}} = \frac{1}{2\pi\sqrt{2H}}\sqrt{\frac{R}{\tau_g}} \qquad (B.18b)$$

Similarly for the peak gain from Eq. B.15:

$$|G_2(j\omega_{max})| \approx \frac{\tau_g}{\sqrt{D^2\tau_g^2 - 4H^2 - 4H\tau_g R + 4H\tau_g R}} = \frac{\tau_g}{\sqrt{D^2\tau_g^2 - 4H^2}} \qquad (B.19)$$

Further simplification is made by noticing that $D^2\tau_g^2 \gg 4H^2$:

$$|G_2(j\omega_{max})| \approx \frac{\tau_g}{\sqrt{D^2\tau_g^2}} = \frac{1}{D} \qquad (B.20)$$

C. Dispatch Model

This appendix explains how the dispatch process is modelled with increasing penetrations of wind generation. Dispatch modelling determines the likely changes in inertia and droop with increasing wind generation, the assumptions that are constructed are designed to accurately predict the number of units synchronised to the grid. The dispatch model is based on the historical dispatch from 2013 to 2015, providing a baseline dispatch solution. The dispatch process is modelled by replacing thermal generation with wind generation over an 11week period, so that energy provided by hydro generation is not spilled. On the 30-minute time scale hydro generation is dispatched, again, to satisfy the daily changes in demand.

C.1. Key Assumptions

Key assumptions are made in modelling the dispatch process, in order to simplify the decisions made by each participant. The main assumptions are based on accurately estimating total system inertia and droop, and the methodology in which wind generation replaces thermal generation.

The purpose of constructing a model of how generation is dispatched, is to determine the implications of wind generation on the quantity of inertia and droop present. The current dispatch provided by the System Operator (SO), where instructions are sent every five minutes, instructs generators to change power generation. Similarly, in the dispatch model, the output is an instruction to change power generation. These instructions do not provide explicit information on how many units are synchronized to the grid. Therefore, a statistical relationship is developed from historical data to estimate how much inertia is present for a given dispatch of generation. This process is then also applied for droop as well.

In New Zealand, there is no tariff or mechanism to encourage wind generation to be built over and above other generation technologies, other than its economic potential, the volition of generator companies to partially suspend economic reasons, and the preference of councils to favor renewable generation in the resource consent process. Therefore, it is not necessarily true, that if wind generation were added to the generation mix, that thermal generation would be displaced as a result. However, for the purposes of the GREEN Grid project with the desires to reduce carbon emissions, and recent closures of thermal plant, it is assumed that all new wind generation will replace thermal generation. If there is an over supply of wind generation then it is assumed that wind generation is curtailed, as other generation technologies provide greater frequency stability and hence a higher priority.

C.2. Overview of the Dispatch Process

The System Operator's dispatch process requires the regular optimization of energy and reserve costs while maintaining energy and reserve constraints. It is not easy to change the inputs to this optimization and still retain an accurate model, because the offers supplied into the market are a complex set of choices determined by resource availability. Any change to the generation mix will affect the offers of the other generators. Therefore, the dispatch model avoids the optimization process, and creates a dispatch based on the energy balance.

Energy is balanced in two stages: the first stage is adding new wind generation and removing thermal generation in equal proportion, i.e. so that energy supplied by the new generation is equal to the thermal energy removed; the second stage balances energy every half hour by changing the power output of the hydro stations. The first stage satisfies the assumption that new wind generation will replace thermal generation. While the second stage accounts for periods when significant wind generation will reduce hydro generation until a period when the wind is not blowing.

C.3. Generation Types

Separating the energy balance into two different stages requires separating the generation mix into four types. Each different type will apply to the energy balance in a different way. These four types are must run generation, thermal generation, new wind generation, and large hydro generation.

C.3.1. Must Run Generation

Must run generation is defined as generation that is not expected to change its dispatch for increases in wind generation. Therefore, must run generation is not included in either energy balancing stage. The inertia and droop contribution from these units is calculated from their historical record. Must run generation includes geothermal, cogeneration, small hydro, hydro with small storage capacity, and historic wind generation. A justification of why each power station was considered must run is enumerated in the following points (a complete list is shown in Table C.1):

- Rangipo and Tokaanu power stations are part of the Tongariro power scheme. Tokaanu has storage in Lake Rotoaira, the storage capacity is estimated to be on the order of being sufficient for one day. Tokaanu therefore has the ability regulate power output to meet demand peaks. However, it has limited ability in shifting electricity generation from one day to the other. Rangipo is considered run of river, i.e. the quantity of electricity generated is primarily determined by the flow rate of the river, rather than the level of the water.
- Matahina, Aniwhenua, and Wheao power stations are along the Rangitaiki River. Aniwhenua and Wheao are run of river; while Matahina is also considered run over river in the model, it has a storage lake of 6.6 Mm^3 and can manage demand peaks.
- Mangahao, Patea, and Kaimai are North Island hydro power stations considered to have enough storage to manage demand peaks, but operate mainly run of river.
- Ideally Tekapo A and B should be counted as one of the main hydro blocks, but during the 2013 and 2014 study period its operation has been inconsistent, due to the redevelopment of their power stations and canals.
- Other South Island hydro generation is must run because of its limited storage, even though most have the ability to follow demand peaks.
- Cogeneration plants – Glenbrook, Te Rapa, Whareroa, Norske Skog, and Kinleith – are not considered thermal units in this analysis, as they have a purpose other than providing electricity. These plants also have limited ability to follow peak demand, and with the exception of Whareroa do not increase generation during dry periods.
- Geothermal power stations are must run as their fuel source is constant.
- Historic wind generation is must run as they have spilled very little energy.
- Whirinaki power station, which only runs infrequently, is considered to be inconsequential whether it is counted as must run or thermal. However, for simplicity is considered must run in this analysis, but in practice is peaking generation.

Table C.1: List of Must Run Generation in New Zealand by island and generation type.

Power Station	Type	Island	Capacity (MW)	Power Station	Type	Island	Capacity (MW)
Rangipo	Hydro	NI	120	Tekapo A	Hydro	SI	32
Tokaanu	Hydro	NI	240	Tekapo B	Hydro	SI	157
Mangahao	Hydro	NI	40	Argyle	Hydro	SI	11
Aniwhenua	Hydro	NI	25	Highbank	Hydro	SI	29
Patea	Hydro	NI	32	Waipori	Hydro	SI	90
Matahina	Hydro	NI	80	Cobb	Hydro	SI	32
Wheao	Hydro	NI	26	Coleridge	Hydro	SI	39
Kaimai	Hydro	NI	40	Kumara	Hydro	SI	7
Glenbrook	Cogen	NI	69	Paerau	Hydro	SI	12
Te Rapa	Cogen	NI	50	Ohaaki	Geo	NI	105
Whareroa	Cogen	NI	70	Poihipi	Geo	NI	55
Norske Skog	Cogen	NI	49	Te Mihi	Geo	NI	166
Kinleith	Cogen	NI	40	Wairakei	Geo	NI	132
Te Uku	Wind	NI	64	Kawerau	Geo	NI	100
Te Apiti	Wind	NI	90	Te Huka	Geo	NI	28
Mill Creek	Wind	NI	60	Ngatamariki	Geo	NI	82
West Wind	Wind	NI	143	Rotokawa	Geo	NI	34
Te Rere Hau	Wind	NI	49	Nga Awa Purua	Geo	NI	138
Tararua	Wind	NI	161	Mokai	Geo	NI	112
White Hill	Wind	SI	58	Whirinaki	Diesel	NI	155
Mahinerangi	Wind	SI	36				

C.3.2. Thermal Generation

Thermal generation is electricity generated from gas or coal. These generators have recently been the first generation assets to be removed from the market. Therefore, the dispatch model replaces thermal generation with new wind generation in the first energy balance. Thermal stations are listed in Table C.2; since the analysis period is from 2013 to the end of 2015, the list also includes thermal stations that have since closed.

Table C.2: List of New Zealand thermal power stations.

Thermal Power Stations	Capacity (MW)	Thermal Power Stations	Capacity (MW)
Huntly Units 1 to 4	1015	Stratford Peakers	210
Huntly Unit 5	405	Taranaki CCGT	400
Huntly Unit 6	49	Kapuni	20
Southdown	177	McKee	100
Otahuhu	400		

C.3.3. New Wind Generation

New wind generation is modelled by simulating potential wind farm sites. The simulation was undertaken by Dougal McQueen as part of his doctoral research. A combination of these wind farm sites is used to develop scenarios, Appendix D. The scenarios are created to achieve an even distribution of wind farms across New Zealand.

C.3.4. Hydro Generation

The main hydro generation is analysed in blocks: Waikato, Waikaremoana, Waitaki (excluding Tekapo stations), Clutha, and Manapouri schemes. Table C.3 lists the stations within each scheme. The purpose of analysing hydro power stations in blocks is to minimise the complexity of the dispatch, and improving the estimation of inertia and droop.

Complexity is minimized by not having to dispatch individual power stations within a scheme. Thereby removing the need to analyse water flows, reservoir levels, etc. The schemes can be dispatched on a continuous operating range, whereas individual power stations cannot. Normally a hydro power station is dispatched to their most efficient operating points, which is somewhere between 70% and 90% of their maximum power output for each turbine depending on the amount of hydrological head, and turbine design. Therefore, any given hydro power station will maintain a power output on certain number of discrete levels, depending on the number of turbine units. Combining hydro power stations allows for a greater continuum of operating ranges, which is ideal for the formulation of the model hydro dispatch. Waikato and Waitaki schemes, with a large number individual power stations, provide a greater continuum of operating points compared to Manapouri. Hence, Manapouri power station is not highly suited for this hydro dispatch.

The estimation of inertia and droop is not affected by this simplification either. In the System Operator's dispatch, even though individual power stations within a scheme are sent dispatch instructions, the scheme can manage its resources across each unit, hence the power output of an individual power station will not match the dispatch instruction. Therefore, when estimating inertia, it is inaccurate to develop a correlation between the System Operator's dispatch and the total inertia of the power station, it would be more accurate if inertia was correlated against power output of the whole scheme.

Table C.3: Large hydro power stations, by scheme, used in the second stage of the dispatch model.

Scheme	Power Station	Capacity (MW)
Waikato	Aratiatia	82
	Ohakuri	111
	Atiamuri	82
	Whakamaru	102
	Maraetai	318
	Waipapa	59
	Arapuni	192
	Karapiro	101
Waikaremoana	Piripaua	44
	Tuai	63
	Kaitawa	36
Clutha	Clyde	464
	Roxburgh	346
Waitaki	Ohau A	256
	Ohau B	208
	Ohau C	208
	Benmore	534
	Aviemore	216
	Waitaki	90
Manapouri	Manapouri	848

C.4. Steps in the Dispatch Process

C.4.1. List of Indices, Parameters, and Variables

Indices in the Thermal Dispatch

g thermal power station

i trading period

j day

k block of days to balance energy

p the marginal thermal power station that can be fully removed from the market

Parameters in the Thermal Dispatch

T historical generation from thermal units

W available wind generation from potential scenarios of extra wind capacity

L perturbed lower limit in hydro generation

U perturbed upper limit in hydro generation

Variables in the Thermal Dispatch

S simulated dispatch of thermal generation

X simulated dispatch of wind generation from scenarios

Indices in the Hydro Dispatch

g hydro power station

m, n trading period

Parameters in the Hydro Dispatch

H historical generation from hydro schemes

B results from thermal dispatch on the required change in the hydro dispatch

L perturbed lower limit in hydro generation

U perturbed upper limit in hydro generation

ML minimum generation level

MU maximum offered generation into the market

SF historical reserves dispatched by hydro scheme

α gain of the hydro reservoir management loop

β relative distribution of storage between reservoirs

η energy conversion effectiveness from volume of water stored to electricity generated for a reservoir

R reservoir size

Variables in the Hydro Dispatch

ΔH total change in hydro generation dispatch

ΔHC change in hydro generation dispatch to satisfy the change in thermal dispatch

ΔHS change in hydro generation dispatch to manage reservoir and energy storage

ΔLS change in reservoir storage

λ relative capacity distribution among hydro schemes

C.4.2. Introduction

The process of dispatching thermal, new wind generation, and hydro generation is broken down into three steps. Each of these steps are discussed in detail.

1. Thermal Dispatch
2. Hydro Capacity Time Series
3. Hydro Dispatch

C.4.3. Thermal Dispatch

The thermal dispatch is a process of replacing thermal generation with new wind generation, so that the amount of energy introduced by new wind generation is equal to the energy removed by the displacement of thermal generation. The energy balance is completed for each 11week period, over a time range from 2013 to 2015. That is for 1155 days in 2013, 2014, and 2015, those days are split into 11 week periods to give a total of 15 blocks, for which the total amount of thermal generation removed has to balance with the total amount of new wind generation added. There is only 1095 days from 2013 to 2015 therefore 60 days are obtained from the end of 2012 and the start of 2016, roughly evenly. A period of 11 weeks ensured hydro reservoir levels were managed successfully within the current paradigm, this justification is provided in the section on the hydro dispatch.

Definition of Variables

The thermal dispatch starts with obtaining 30-minute metered generation data – from the Electricity Authority dataset – and grouping each trading period by day, 11-week block, and generator. Historical thermal generation is represented by T_{ijkg}, where i is an index of trading periods from 1 to 48, j is an index of days from 1 to 77 (11 weeks), k is an index of 11-week blocks from 1 to 15 (sufficient to cover the years 2013 to 2015 with enough overlap). The last subscript, g, is an index of thermal generators. The units of T are MWh. These indices can be summated over, for example, i, the total generation by day (and similarly for the other indices):

$$T_{jkg} = \sum_{i} T_{ijkg} \qquad (C.1)$$

The new wind generation for a scenario is W_{ijk}, where the indices refer to the same quantities. T_{ijkg} and W_{ijk} do not change in the dispatch, rather they are the inputs. The outputs are S_{ijkg} the dispatched thermal generation, and X_{ijk} the dispatched wind generation. Once the thermal dispatch is complete, W and X may not necessarily equal, as there may be too much wind generation and therefore new wind generation has to be curtailed. The last variable to be defined is an upper and lower limit, U_{ijk} and L_{ijk}, these are the maximum possible change in hydro generation, and therefore the maximum possible change in thermal and wind generation.

The Objective

The objective of the thermal dispatch is to achieve an equality in the new dispatch compared to the historical thermal dispatch (NB, the absence of the ij indices means that total energy in the 11-week block is important here, not every trading period):

$$X_k + S_k \approx T_k \qquad (C.2)$$

It is not possible to achieve the objective with equality, as the process of deriving the relationship does not achieve it. However, the relationship is close to equality:

$$|X_k + S_k - T_k| < 0.01T_k \qquad (C.3)$$

The Thermal Dispatch Process

The process of deriving the thermal dispatch is presented in the flow chart shown in Figure C.1. The thermal dispatch process can be solved independently for each 11-week period, as the output of one period does not feed into the next. Therefore, the process for one period is repeatedly applied to the subsequent periods.

The choice to curtail new wind generation, or remove thermal

The first decision is to determine whether there is more available wind generation than what is required. If there is insufficient wind generation, then choosing which thermal generation to remove becomes important. However, if there is sufficient wind generation, then the problem is not which thermal generation to be removed, as it will all be removed, but how to curtail wind generation in the most appropriate way.

The first step in removing thermal generation

The first step is to determine whether the complete energy output of one generator can be removed, e.g. for an 11 week period, is it possible to remove all the output from Otahuhu power station. This is not limited to just one complete unit, but to how many more complete units can be removed as well. The purpose of removing by complete units first, is to account for the cost of having capacity, i.e. is the capital costs. If capacity is removed then cost of the system reduces, hence the thermal dispatch is trying to emulate the complete removal of power stations from the market.

The choosing of index p from the equation shown in Figure C.1 implies a hierarchy in thermal generators:

$$\sum_{g=1}^{p} T_{kg} < W_k \qquad (C.4)$$

There is a consistent order in which generators are checked first if they can be removed as a complete unit. This hierarchy starts from $g = 1$, the first generator that is to be checked, to $g = 10$ the last generator to be checked. The hierarchy is listed presented in Table C.4.

Table C.4: Hierarchy of thermal generation units in the order of being removed from the market.

Index	**Thermal Unit**
1	Huntly Unit 3
2	Southdown
3	Otahuhu
4	Huntly Units 1, 2, and 4
5	McKee
6	Taranaki Combined Cycle
7	Huntly Unit 6
8	Stratford Peakers
9	Kapuni
10	Huntly Unit 5

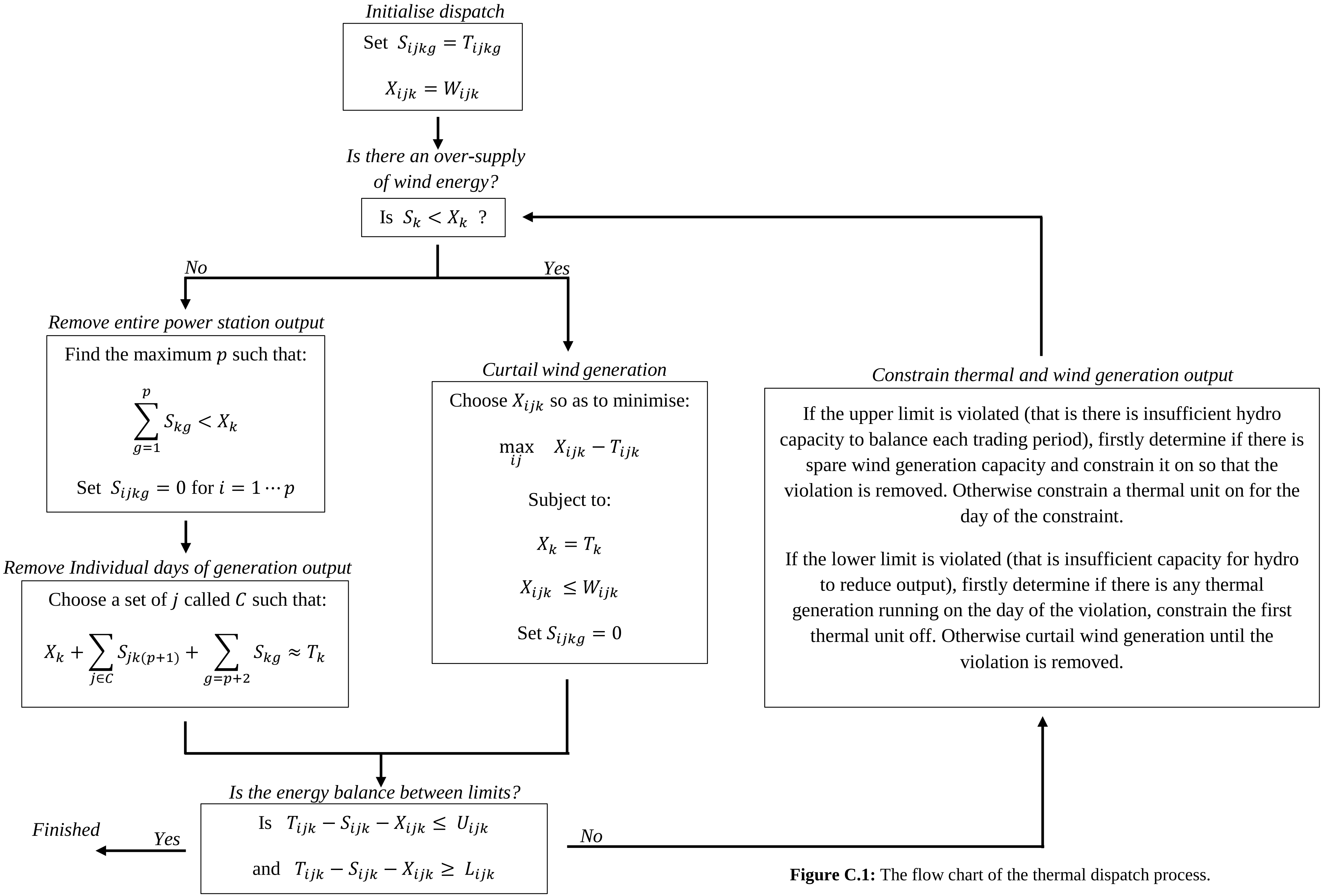

Figure C.1: The flow chart of the thermal dispatch process.

The hierarchy is firstly determined by which units have already been removed from the market. Huntly Unit 3 has been out of operation for largest amount of time, and during the analysis period it only ran for one day at the start. Southdown and Otahuhu are next as they have since been removed from the market; Southdown is placed prior to Otahuhu as the news that Southdown would exit came before Otahuhu. Huntly Rankine units are next due to the proposal that they will be removed in the near future, which has since been revised. McKee, Taranaki Combined Cycle, and Huntly Unit 6 are placed next, as their use is more sporadic, than the next three units.

The second step in removing thermal generation

The second step is to remove thermal generation in day blocks, which provides the finest method of balancing new wind generation and thermal generation. This balancing is only applied to the next generator on the hierarchy list, e.g. if Huntly Unit 3 and Southdown units were completely removed by the previous step, then generation will only be removed from Otahuhu. Days with large amounts of wind generation determine the days to remove thermal generation. This is to reduce the difference between the historical dispatch of thermal generation and the new dispatch.

Energy balancing of thermal and wind energy is not extended to the 30-minute time scales, this is to avoid situations where a thermal unit is switching from full output to zero and back to full repeatedly. This preserves the nature of thermal plant management, as plant cycling is minimised.

Curtail wind generation

Wind energy is curtailed when wind energy is greater than thermal energy. The methodology in curtailing wind generation is to flatten the peaks in wind generation. This is to avoid high levels of wind generation at any one point in time.

Limitation on Dispatch

The hydro dispatch, requires that difference between the new dispatch and the old dispatch lie within the upper and lower limit. More specifically, the changes in the hydro dispatch, caused by the new thermal dispatch, have to be in within the minimum and maximum generation range for the hydro units. The details of how the limits are determined are given in the next section.

If the new dispatch violates the upper and lower limits, then either thermal generation or wind generation is constrained in order to remove the violations, and the dispatch is recalculated to balance the energy. This step is repeated until all the violations are removed.

C.4.4. Hydro Capacity Limit

The hydro capacity limit determines the valid range in which the main hydro generators can operate. This limit is applied to both the thermal dispatch and the hydro dispatch. In the thermal dispatch, the limit sets the valid solutions for choosing which thermal and wind generation remains. For the hydro dispatch it effects the relative contribution of generation from each scheme.

The positive limit, that is maximum capacity of the generating unit, is set by the maximum limit in their generation offers and by how much Instantaneous Reserves is dispatched at that time. The maximum positive limit is determined by following equation:

$$U_{ijkg} = MU_{ijkg} - SF_{ijkg} - H_{ijkg} \qquad (C.5)$$

where MU_{ijkg} is the maximum generation capacity set in the generation offer, SF_{ijkg} is the larger amount of FIR or SIR dispatched from that hydro generator in the trading period, and H_{ijkg} is the historical amount of generation provided by that unit. The negative limit is how much a hydro generator can reduce output before it reaches its minimum generation.

$$L_{ijkg} = ML_{ijkg} - H_{ijkg} \qquad (C.6)$$

Where ML_{ijkg} is the estimate of the minimum output of each hydro scheme. This value is estimated for each hydro scheme from the historical minimum power output, Table C.5.

Table C.5: Minimum generation levels of main hydro power schemes.

Hydro Scheme	Minimum Limit (MW)
Waikato	47
Waikaremoana	12
Waitaki	100
Clutha	90
Manapouri	75

C.4.5. Hydro Dispatch

The hydro dispatch is necessary to balance the 30 minute variation created by the thermal dispatch. Hydro dispatch is designed to account for periods when there are large amounts of wind energy being produced, and therefore hydro generation has to be reduced for a period, and vice versa. The hydro dispatch considers both the capacity of hydro stations, and the availability of storage in their reservoirs.

The hydro dispatch is completed on the block level, e.g. Benmore will not be dispatched individually, but the Waitaki scheme is dispatched as a group. There are several advantages to this methodology. Firstly, individual hydro stations tend to operate on discrete levels set by the maximum efficiency of each turbine, combining power stations together allows for continuum of operating points. This assumption is valid for Waikato, Waitaki and to a lesser extent Clutha system. However, it is not so accurate for Waikaremoana and Manapouri systems, because there are fewer power stations. This impact is considered inconsequential given the methodology of determining inertia and droop.

Secondly, canal and reservoir dynamics do not have to be considered, other than the main reservoir at the top of the system. If individual power stations were modelled, then the flow of water between minor reservoirs in the system is required. Keeping the dispatch level to a block level reduces the number of constraints that have to be formulated.

Definition of Parameters and Variables

The parameter, H, is historical hydro generation, which is obtained from the Electricity Authority. The results of the dispatch give a perturbation from the historical generation, ΔH, which are further separated into two components, the perturbation in proportion to available capacity, ΔHC, and the perturbation to manage reservoir storage levels, ΔHS:

$$\Delta H_{mg} = \Delta HC_{mg} + \Delta HS_{mg} \qquad (C.7)$$

The index, m, refers to each individual trading period, and is equivalent to ijk expanded, i.e. no distinction is made between day and 11 week block, and each trading period flows from each other. In the hydro dispatch the process is not compartmentalised into separate periods as the process of dispatching hydro is sequential, the output from the previous trading period is an input for the next trading period. The index, g, refer to individual hydro blocks, e.g. $g = 1$ refers to the Waikato scheme. In the hydro dispatch the units are in MW, the transfer of parameters between the thermal dispatch and the hydro dispatch assume a scaling of 0.5, to go from MW over a half hour to MWh.

The next parameter is energy stored in the main reservoir lakes. ΔLS is the perturbation in lake storage level and is calculated from the perturbation in hydro dispatch by:

$$\Delta LS_{ng} = -\frac{1}{2}\sum_{m=1}^{n} \Delta H_{mg} \qquad (C.8)$$

The units of ΔLS are in MWh, and n is an index of trading periods. ΔLS can be converted to Mm^3, the volume of water in the lakes, by the conversion factors of each hydro scheme, assuming each Mm^3 in the head reservoir goes through each of the power stations. These conversion factors are listed in Table C.6. The negation in Eq. C.8 means that as more electricity is produced, the less water is stored in the reservoir.

Table C.6: Conversion factors from unserved energy to volume of water in the head reservoir for each hydro scheme.

Hydro Scheme	**Conversion Factor, (1000 m^3/MWh)**
Waikato	1.48
Waikaremoana	1.02
Waitaki	1.37
Clutha	3.91
Manapouri	2.35

The Objective

The objective of the hydro dispatch is to satisfy the thermal dispatch imbalance (NB, that the absence of the g index infers that the total hydro generation is required):

$$\Delta H_m = T_m - S_m - X_m = B_m \qquad (C.9)$$

Where B_m is the difference between the old dispatch and the new dispatch. The process of determining ΔH_{mg} is split into two components: balance in proportion to capacity, and balance in proportion to storage availability. This process is described in Figure C.2. The process is iterative, starting with the first trading period, and then moving onto the next.

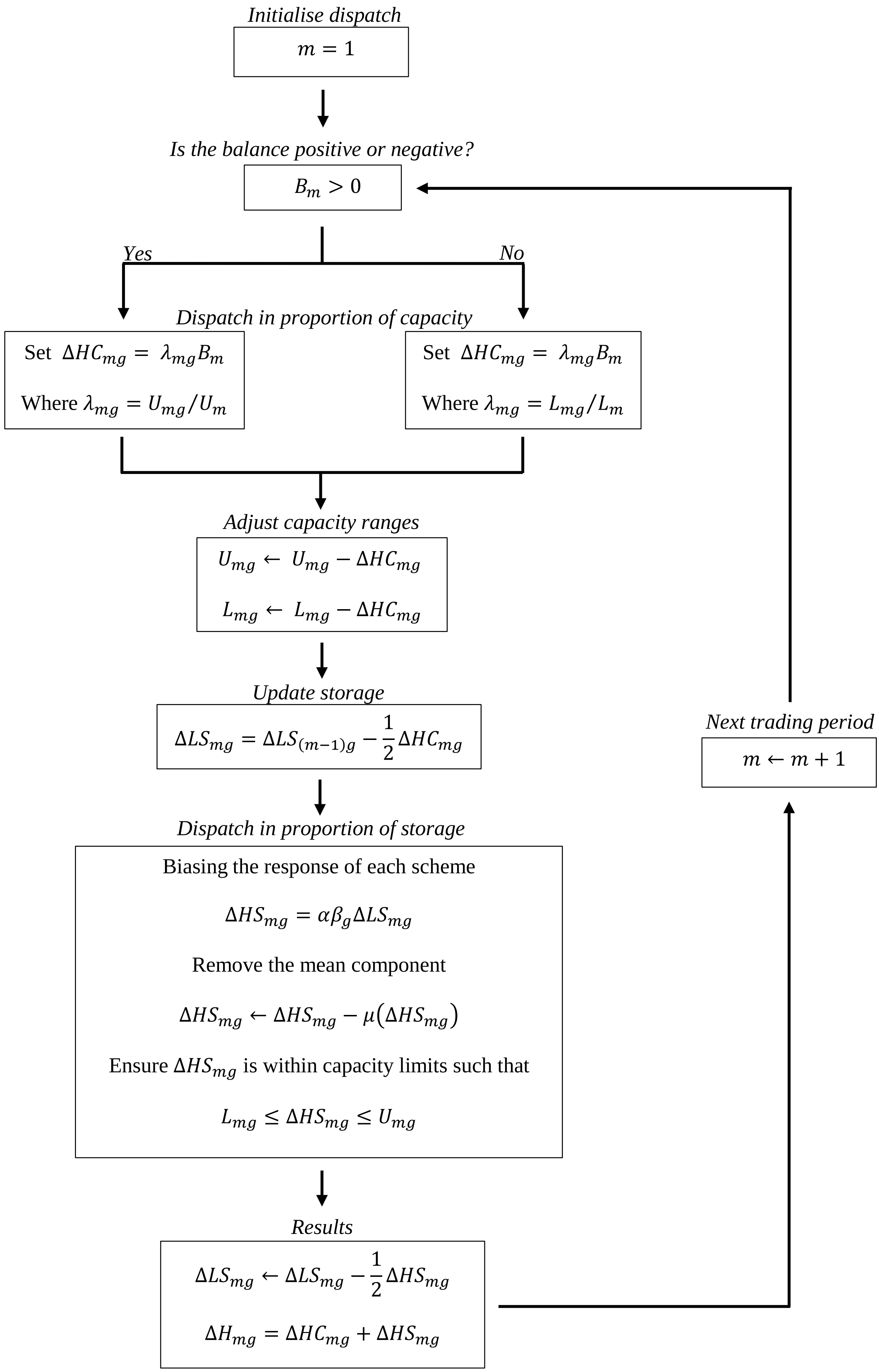

Figure C.2: The flow chart of the hydro dispatch process.

Dispatch in Proportion of Available Capacity

The first step is to ensure $\Delta HC_m = B_m$, i.e. entire imbalance caused by the thermal dispatch is satisfied by the dispatch of hydro generation. The change in dispatch for each hydro scheme is determined in proportion to the available capacity. $\Delta HC_m = B_m$ is satisfied by the formulation of λ_{mg}, where:

$$\sum_g \lambda_{mg} = 1 \qquad (C.10)$$

The available capacity is determined from whether the imbalance is in the negative direction or in the positive direction. If the negative direction, the lower limits determine the available capacity.

Dispatch in Proportion of Available Storage

The second step is to manage lake levels within lake limits, this is primarily done by the thermal dispatch which is balanced over an 11 week period; however to ensure the proper management of each individual hydro scheme the hydro dispatch is biased. The objective of this step is to have $\Delta LS_{mg} = 0$, however this is not possible all the time due to hydro capacity constraints and the deviation created by the thermal dispatch. Therefore ΔHS_{mg}, the change in hydro dispatch to manage storage level, is determined to ensure that no one scheme is used more often than another. This step is necessary to ensure that the correct amount of inertia and droop is present, as each scheme is used in a sustainable manner.

To dispatch hydro generation in proportion of available storage, firstly, the capacity limits of each hydro scheme are adjusted by the dispatch in proportion of available capacity:

$$U_{mg} \leftarrow U_{mg} - \Delta HC_{mg} \qquad (\mathrm{C}.11\mathrm{a})$$

$$L_{mg} \leftarrow L_{mg} - \Delta HC_{mg} \qquad (C.11b)$$

This is to determine the current range both in the positive and negative directions in which the hydro scheme can operate. Secondly, ΔHS_{mg} is biased in proportion to the deviation in hydro storage:

$$\Delta HS_{mg} = \alpha \beta_g \Delta LS_{mg} \qquad (C.12)$$

The biases, α and β_g, determine the speed at which the system reaches equilibrium and the relative equilibrium. The nature of the equilibrium and how the biases are chosen are discussed further; however, the whole process requires explanation first. Thirdly from dispatching in proportion to capacity results in $\Delta HC_m = B_m$, hence $\Delta HS_m = 0$ in order to satisfy Eq. C.7 and Eq. C.9, and so ΔHS_{mg} requires a zero average:

$$\Delta HS_{mg} \leftarrow \Delta HS_{mg} - \mu(\Delta HS_{mg}) \qquad (C.13)$$

where μ is a function that calculates the mean. Fourthly, at this stage ΔHS_{mg} may not be within the limits of L_{mg} and U_{mg} therefore a process is used to reduce the magnitude of some components of ΔHS_{mg} while retaining its zero mean property. A full explanation of this process is not given, but in involves checking each limit and shifting generation amongst schemes. Lastly the final results are calculated, both the final storage and the final dispatch.

In this process there is a feedback loop, which results in an equilibrium point provided enough iterations, i.e. enough trading periods to process through. The process of Figure C.2 is redrawn to help clarify where the feedback loop is, Figure C.3. The loop is stable because of the negative feedback term of $-1/2$.

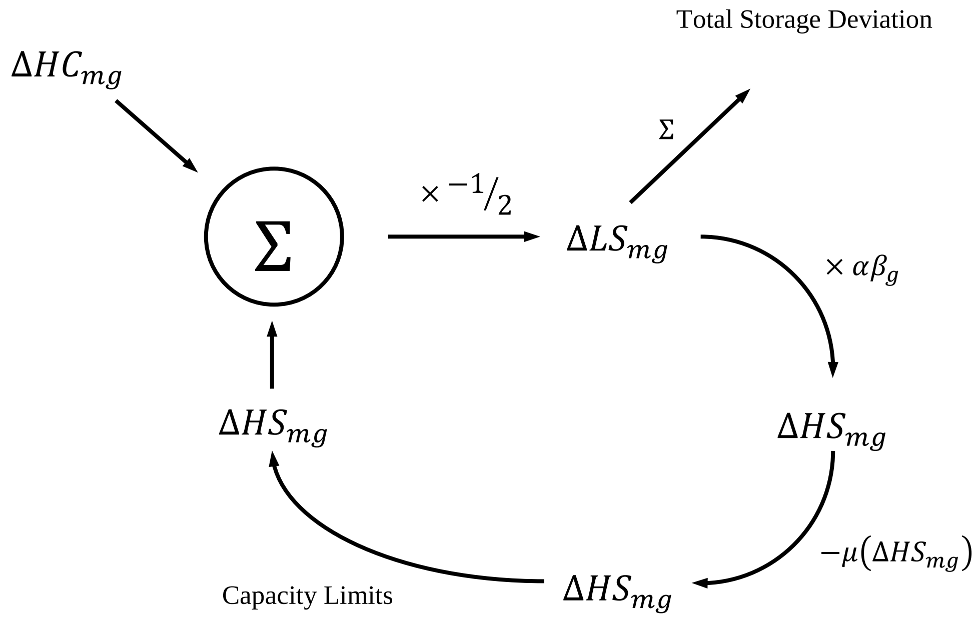

Figure C.3: The feedback loop between the deviation in storage level and the dispatch in proportion to available storage.

The equilibrium refers to a tendency in ΔLS_{mg} to retain the same relative difference between hydro schemes, i.e.

$$\frac{\Delta LS_{mi}}{\Delta LS_{mj}} \approx \frac{\Delta LS_{ni}}{\Delta LS_{nj}}, \quad where\ i \neq j, and\ m \neq n \tag{C.14}$$

This relationship is not retained exactly, due to the external input in the loop, ΔHC_{mg}, and so equilibrium is never properly reached. However, it is helpful to consider conditions for which the final ΔHS_{mg} is zero and does not change ΔLS_{mg}, so that an appropriate choice of β_g can be made, which determines the relative storage in each lake, i.e. the ratios of Eq. C.14.

Starting with the last ΔHS_{mg} in Figure C.3 and working backwards through the loop, the first operation is to ensure capacity limits are meet. There are two possible cases: either the capacity limits were not satisfied or they were satisfied. If they were not, then the system is not in a state of equilibrium, and ΔHS_{mg} was not equal to zero prior to this operation. This is not considered a state of equilibrium, because if the capacity limits changed in the next trading period the result would not be zero and clearly not in equilibrium. Therefore, to be in equilibrium, ΔHS_{mg} has to equal zero prior to ensuring the capacity constraints were meet.

The next operation is to remove the mean from the signal, since the value of the mean does not determine whether the system is in equilibrium or not, the mean is arbitrarily defined:

$$\mu_{HS} = \mu(\Delta HS_{mg}) \tag{C.15}$$

And ΔHS_{mg} prior to removing the mean is μ_{HS}. The next operation results in:

$$\Delta LS_{mg} = \frac{\mu_{HS}}{\alpha\beta_g} \tag{C.16}$$

Thereby implying that the system is in equilibrium if:

$$\Delta LS_{mg}\beta_g = constant \qquad (C.17)$$

Where β_g determines the relative proportion from each hydro scheme. For example, if $\beta_1 = 2$ for the Waikato scheme and $\beta_3 = 1$ for the Waitaki scheme then the system will tend towards having $2\Delta LS_{m1} = \Delta LS_{m3}$, i.e. the deviation in storage in Lake Pukaki will be twice as much as it will be in Lake Taupo. Therefore, in choosing the values of β_g to get the best utilization of available storage, β_g should reflect size of each individual storage reservoir. That is the largest reservoirs should have the smallest β_g, while the smallest reservoirs should have the largest β_g.

The size of the reservoir is not sufficient to give an accurate choice of β_g, as the value of one Mm^3 in one reservoir is not the same as in another, as each scheme has a different combined head (water pressure), i.e. Lake Hawea is at a different elevation to Lake Taupo, and passes through a different number of water ways and power stations. The value of one Mm^3 is expressed in Table C.6, where in the Waikato scheme it requires 1,480 m^3 in Lake Taupo to produce one MWh, while it requires 3,910 m^3 in Lake Hawea to produce one MWh. The impact this has on the choice of β_g, is that reservoirs that are less effective in storing energy should store a smaller amount of the MWh required. Hence for the Clutha scheme should have a larger β_g than Waikato scheme.

Therefore, considering the reservoir size and efficiency, β_g is calculated as:

$$\beta_g = \frac{\eta_g}{R_g} \qquad (C.18)$$

Where η_g is the water conversion factor presented in Table C.6, and has units of m^3/MWh. R_g is the reservoir size in Mm^3. The units of β_g are m^3/MWh/Mm^3. The parameters of each hydro scheme are presented in Table C.7. From this choice of β_g, the Waitaki scheme would ideally have about 11.2 times as much of the energy imbalance as the Waikaremoana scheme, 6.2 times that of the Clutha scheme, 4.1 times that of the Manapouri scheme, and 3.1 times that of the Waikato scheme. In total, the Waitaki scheme should store 20 % (1.2 times) more of the energy imbalance than the other schemes combined. However, the Waitaki scheme has a generation capacity of 1540 MW, which is about 54% the size of the other generators combined of 2830 MW, the ability that the Waitaki scheme has in storing 20% more energy is limited by the available capacity of its plant.

Table C.7: The parameters of each hydro scheme to calculate the bias, β_g.

Hydro Scheme	**Conversion Factor, $\boldsymbol{\eta_g}$** m^3/MWh	**Reservoir Size, $\boldsymbol{R_g}$** Mm^3	**Relative Bias, $\boldsymbol{\beta_g}$.** m^3/MWh/Mm^3	**Relative Energy Stored, $\boldsymbol{1/\beta_g}$** MWhMm^3/ m^3
Waikato	1480	860	1.72	0.58
Waikaremoana	1020	160	6.36	0.16
Waitaki	1370	2430	0.56	1.79
Clutha	3910	1150	3.40	0.29
Manapouri	2350	1030	2.28	0.44

Once the relative bias, β_g, is determined, the next bias to set is α, which sets the gain of the whole loop. The larger the gain, α, the faster the system will reach equilibrium, but the gain cannot be very large as the output is saturated by the capacity limits of each scheme. Also the rate does not need to be any faster than speed at which the system can deviate from equilibrium, but this is more difficult to determine and depends largely on which wind generation scenario is chosen. α is chosen to give a comparable ratio between the deviation in energy stored and the capacity of hydro schemes. The value chosen for these simulations is 0.05 MW.Mm^3/m^3.

C.5. Inertia and Droop Estimation

This section describes the process of estimating the total inertia and droop in each island from the dispatch of generation described in the previous sections.

C.5.1. Inertia

The total inertia for each island is calculated from the three types of generation: must run generation, thermal, and hydro. For must run generation, inertia is calculated directly from the historical inertia time series. For thermal generation a similar approach is taken, however if a thermal generator is removed from the mix for a day then the inertia for that plant is zero for that day. The method for finding the inertia of hydro plant is the most involved, and is explained more fully.

Inertia from hydro generation is only considered by hydro scheme, whether that be the Waitaki or Waikato river schemes, or another. This is because each hydro scheme is dispatched as a block, and allows a generator company to optimize water usage and reservoir levels in each system. The first step is to calculate the total generation and reserves; total generation is taken from the redispatch, while reserves are derived from the historical dispatch. The second step is to determine the distribution of possible inertia values for the given generation and reserves, which is derived from the historical distribution. The third step is to use a random variable to estimate an inertia value that is consistent with distribution from the previous step.

For example, the Waitaki scheme – Aviemore, Benmore, Ohau A, B, and C, and Waitaki – the distribution of inertia against total generation and reserves is shown in Figure C.4. This distribution is counted in marked bins as shown in Figure C.5, which gives a likelihood of occurrence as shown in Figure C. 6. For a total generation and reserve of 850 MW, firstly it is noticed that 850 MW lies within the bins from 800 MW to 900 MW. This gives a column of possible inertia values starting at 2,250 MWs and going up to 4,250 MWs, but the most likely bin is from 3,250 to 3,500 MWs. Estimating the inertia value takes a uniformly distributed random variable between 0 and 1 and determines the bin which it falls in. For one trading period the random variable might be 0.3. Since 0.3 is greater than the likelihood of the first bin, then the first bin's inertia is not taken. It is also greater than the likelihood of the first three bins, which is 0.08; however, it is not greater than the first four bins. The inertia lies between 3,000 and 3,250 MWs, and centre value of 3,125 MWs is given as the scheme's inertia.

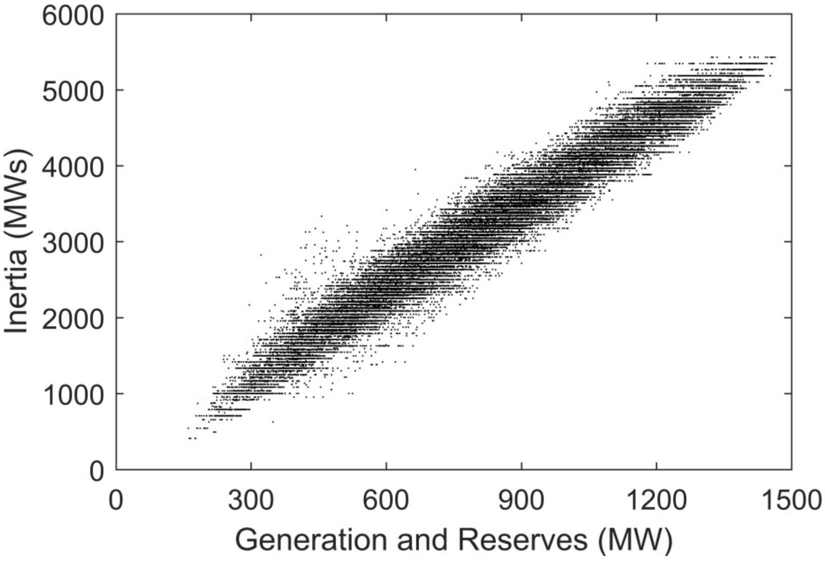

Figure C.4: Distribution of inertia for the Waitaki scheme against its total generation and reserve dispatch.

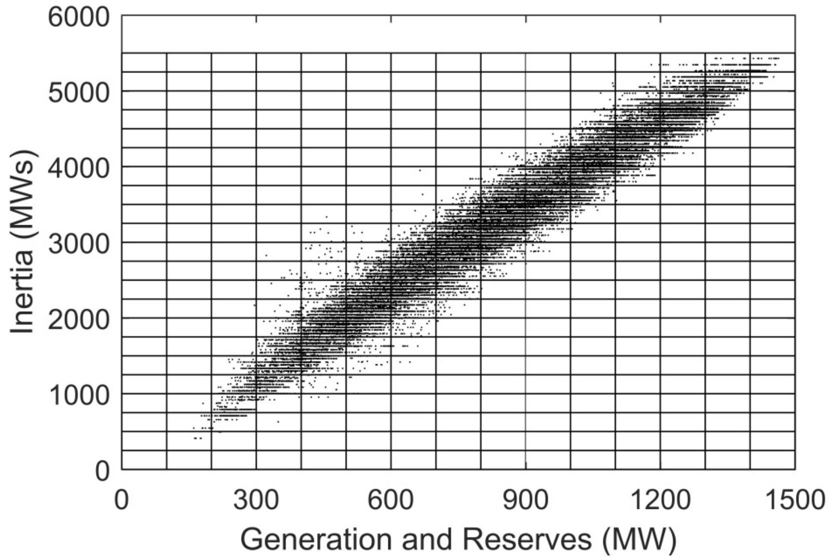

Figure C.5: Edges of the bins used to count the occurrence of inertia values for the distribution of Figure E. 4.

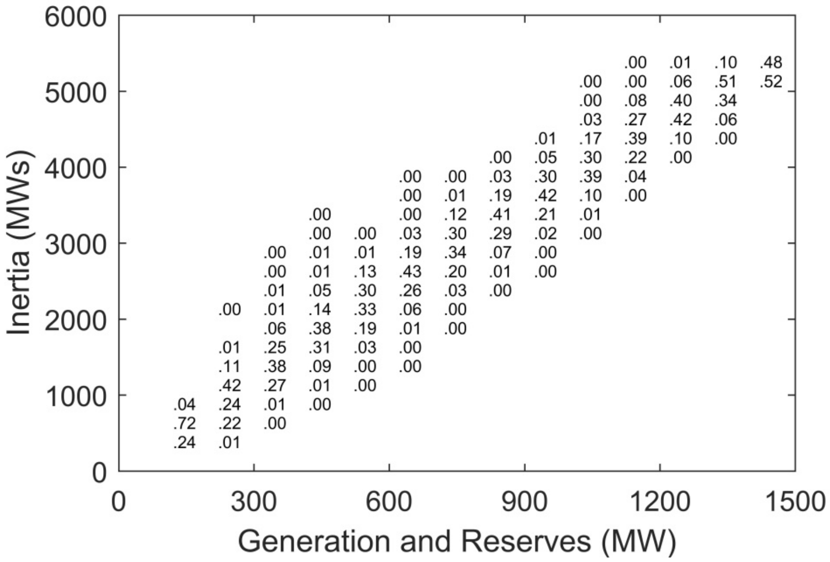

Figure C.6: The likelihood of an inertia value depending on the generation and reserves procured for the Waitaki scheme.

C.5.2. Droop

Droop in this analysis is only counted from hydro generation. This includes must run hydro generation, which is derived from the historical time series, and hydro generation from the main storage lakes, which is estimated from the hydro redispatch. The process of estimating droop is a similar method to that used for inertia, i.e. stochastic. Instead of using the redispatched generation level to estimate droop, the inertia from the previous step is utilised. This approach is taken so that periods of low inertia are better correlated with periods of low droop, to give a better worst-case approximation of the system. The correlation between inertia and droop for the Waitaki scheme is seen in Figure C. 7. For each hydro scheme it is noticeable that there is a highly linear relationship between droop and inertia. Therefore, this relationship is approximated by a linear gain and an error determined by a Gaussian random variable. The linear gain is defined by the gradient of the line of best fit, and the Gaussian random variable has a mean of zero and a standard deviation defined from the standard deviation of the error of the line of best fit to the data.

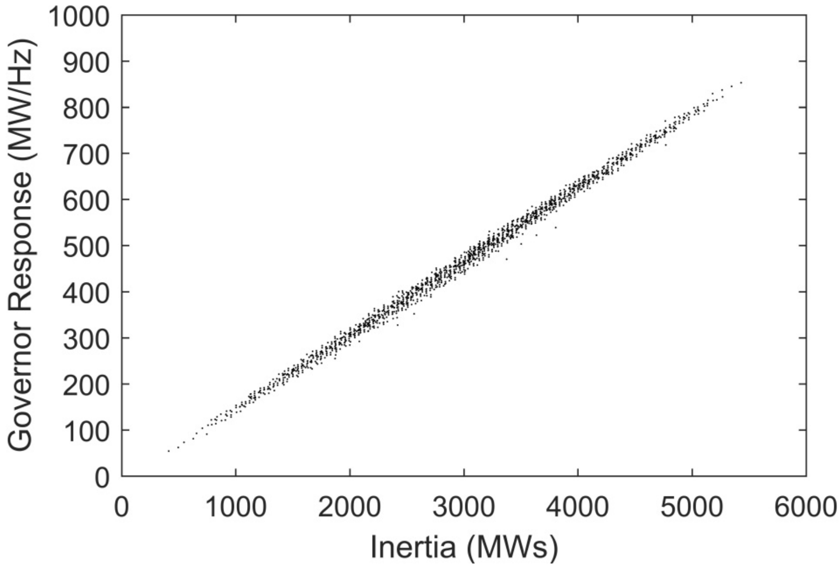

Figure C.7: The distribution of inertia and governor response (droop) for the Waitaki scheme.

D. Wind Generation Scenarios

This appendix provides a description of future wind generation scenarios, and the derivation of the wind power time series used in the analysis. The wind generation scenarios range in size from 500 MW to 4000 MW of extra installed capacity above the current 690 MW of installed wind generation. The wind power time series are based from Dougal McQueen's doctoral thesis work: his method of wavelet imputation and his business as usual scenario; further information about his work can be found here (McQueen, 2016).

The wind generation scenarios follow a quantitative progression, ranging from 500 MW to 4000 MW in 500 MW steps, so as to locate the quantity of generation that will give arise to certain issues, such as when wind generation will be curtailed so that must run generation can run. The range is limited to 4000 MW, an estimate of the amount of generation required in order to achieve a 100% renewable electricity grid. However, as it will be shown in Appendix E, it is difficult to arrive at 100% renewable electricity generation from wind generation alone.

The capacity of the installed wind is insufficient to describe each scenario, as the size and distribution of wind farms within each scenario determine the temporal and spatial correlation between them, and influence the power output and the unpredictability at any point in time. Therefore, a description of each scenario is presented in Table D.1. The wind farms that comprise each scenario are those that have been consented, e.g. Castle Hill has a proposed capacity of 858 MW and is distributed between the first six scenarios, where between 100 to 200 MW of capacity is added in each scenario. Each scenario tries to evenly distribute the location of wind farms, thereby benefiting from the spatial diversification; this is difficult to do objectively, so a more eclectic approach was taken.

Since there is approximately only 3000 MW of wind generation consented for, the last 1000 MW was constructed from further proposed wind farms that had either failed to obtain consent or had lapsed consent.

Table D.1: Future wind generation scenarios.

	North Island		South Island	
Scenario	Wind Farm	Capacity (MW)	Wind Farm	Capacity (MW)
500 MW	Castle Hill	100	Hurunui	71.3
	Taharoa	63	Kaiwera Downs	50
	Central Wind	50	Puketoi	50
	Hauauru Ma Raki	50		
	Turitea	35.2		
	Awhitu	18		
	Long Gully	12.5		
Total		328.7		171.3
1000 MW	Castle Hill	100	Mahinerangi	50
	Hauauru Ma Raki	100	Puketoi	50
	Central Wind	69.6	Mt Cass	40.4
	Maungaharuru and Titiokura	50	Kaiwera Downs	40
Total		319.6		180.4
1500 MW	Castle Hill	150	Puketoi	100
	Hauauru Ma Raki	100	Mahinerangi	55.2

	Turitea	44.8	Kaiwera Downs	50
Total		294.8		205.2
2000 MW	Castle Hill	200	Kaiwera Downs	50
	Hauauru Ma Raki	50	Puketoi	50
	Maungaharuru and Titiokura	50		
	Turitea	50		
	Waitahora	50		
Total		400		100
2500 MW	Castle Hill	150	Puketoi	60
	Hauauru Ma Raki	100	Mahinerangi	58.8
	Waitahora	56		
	Turitea	50		
	Maungaharuru and Titiokura	25.2		
Total		381.2		118.8
3000 MW	Castle Hill	158	Puketoi	58
	Hauauru Ma Raki	104	Kaiwera Downs	50
			Project Hayes	50
			Slopedown	42.4
			Mt Cass	37.6
Total		262		238
3500 MW	Ahipara / Gumfields	50	Project Hayes	100
	Belmont	50	Cape Campbell	50
	Motorimu	50		
	Pouto Forest	50		
	Puketiro	50		
	Te Waka	50		
	Waverly	50		
Total		350		150
4000 MW	Pouto Forest	70	Project Hayes	80
	Awakino	50	Mt Stalker	50
	Mt Munro	50	Roundtop	50
	Omamari	50	Tiwai	50
	Windy Peak	50		
Total		270		230

D.1. Wind Power Time Series

The simulation of wind power time series is necessary for analysing the unpredictability of future wind generation scenarios, and the unit commitment of generation. Therefore, wind power time series requires accuracy in simulating the spectral composition of the time series (for unpredictability) and the magnitude of the time series (for unit commitment). This section then describes the process of simulating wind power time series and compares the results against historical wind power time series of current wind generators. The description of the simulation process is a summary of Dougal McQueen’s Thesis (McQueen, 2016).

The simulation process starts with reanalysis wind speed data, where a global model has been used in conjunction with measured weather data to derive wind speed data at unknown locations, but at a time in the past. This data has been provided by European Centre for Medium range Weather Forecasting (ECMWF). The resolution is 0.7° longitude by 0.7° latitude (roughly 80 km), with 6 hour sampling, at an altitude of 10 meters above a flat surface. The reanalysis wind speed data is useful ensuring that yearly wind generation patterns are correctly correlated with hydro generation patterns, and any other type of generation with a yearly pattern dependent on the weather. With wind generation output correlated with hydro generation, the availability of generation for unit commitment is more accurately modelled. Diurnal patterns are also partly modelled by the 6 hour temporal resolution.

The next step is to interpolate the data from the 0.7° grid to the location of the wind farm. Then the wind speed is scaled from its 10 m height value to the hub height of the wind turbines. This scaling also considers factors such as the geographical location and terrain. There are a number of methods in which this can be done, however the scaling method that was chosen is based on achieving a 40% capacity factor. As some of New Zealand's wind farms have a Capacity Factor of 40% this is a suitable approximation.

Table D.2: Capacity factor of New Zealand wind farms, the energy production of each wind farm is calculated from the Electricity Authority's Generation Dataset. There is insufficient data for results on Mahinerangi and Mill Creek wind farms.

Wind Farm		**Capacity**	**Capacity Factor (%)**		
Name	ID	(MW)	2013	2014	2015
Te Uku	TUK	65	35.7	38.1	36.4
Te Apiti	TAP	91	38.8	39.2	35.8
Tararua I and II	TWF	73	37.4	40.4	40.3
Tararua III	TWC	93	39.1	40.5	40.4
Te Rere Hau	TRH	49	25.6	29.8	28.6
West Wind	WWD	143	40.1	42.6	42.3
White Hill	WHL	58	36.7	32.9	35.5

The wind speed time series is now at the correct location and the right altitude, but the temporal resolution is 6 hours. The next step is to increase the temporal resolution; the methodology constructs a stochastic model that accurately reflects the nature of wind speed in the climate through the use of wavelets. The stochastic model retains the spatial and temporal correlation of separate locations, thereby ensuring accurate predictions of the combined output of each scenario.

Once the temporal resolution has increased to approximately a 5 minute interval, a low pass filter is applied to account for the smoothing effect that multiple wind turbines have on the combined power output of the wind farm, as the uncorrelated nature of fast speed fluctuations partially destructively interfere. A Power curve for the entire wind farm is applied to obtain a wind power time series. Finally, a scaling is applied to account for the operational state of the wind turbines, e.g. whether a turbine is disconnected for maintenance, etc. This scaling is modelled by a Markov Chain process.

The simulation process has been applied to the current operational windfarms to assess the performance of the simulation. The accuracy of energy production is assessed by considering the production by day, and more critically by year. Then the ramp rates are analysed to assess the ability to characterise the unpredictability of wind generation.

The use of a hind cast of 6 hours temporal resolution should retain an accurate prediction of the amount of energy produced each day. This accuracy is desired in the process of re-dispatching thermal and hydro generation in the unit commitment problem, as the dispatch of thermal generation is dependent on the daily wind energy production. The performance of the simulation process is presented in Table D.3 by comparing the difference between simulated and the measured energy production of each wind farm.

Table D.3: The accuracy of the simulated power output of each wind farm. Metered energy production of each wind farm was retrieved from the Electricity Authority's Generation Dataset from 2013 to 2015, a total of 1095 days. TWF (LTN) refers to Tararua Stage 1 windfarm while TWF (BPE) refers to Tararua Stage 2 wind farm. The error is the metered output less the simulated prediction.

Wind Farm	Mean Generation[1]	Mean Error, μ		Error Standard Deviation, σ		Min Error	Max Error	R^2	m^3
	MWh	MWh	%	MWh	%	MWh	MWh		
TUK	573	-41	-7.1	269	47	-1024	819	0.79	0.89
TAP	826	-57	-6.9	608	73	-1969	1394	0.43	0.5
TRH	329	-131	-39.9	284	86	-1073	512	0.51	0.64
TWF (LTN)	356	49	13.8	227	64	-684	644	0.47	0.43
TWF (BPE)	334	-12	-3.6	235	71	-751	586	0.48	0.5
TWC	893	-9	-1.1	591	66	-1976	1307	0.47	0.57
WWD	1430	70	4.9	706	49	-2097	1961	0.69	0.79
WHL	488	-70	-14.3	360	74	-1315	943	0.56	0.58
NZ[4]	5229	-200	-3.9	2601	50	-8241	5640	0.62	0.81

1. The mean metered generation per day, the percentage values are referenced to this value.
2. Pearson Correlation Coefficient. 3. The slope of the best fit line applied to the data.
4. New Zealand is the summation of the listed wind farms to the exclusion of Mahinerangi, White Hill, and the other minor wind farms.

The simulated power output does over estimate energy production, which is likely due to an over estimation of the capacity factor, as seen when considering Te Rere Hau wind farm. However the overall energy production of New Zealand is generally positive with only a 3.9 % error on average, secondly the simulated output better correlates with the measured power output, as seen by a correlation coefficient of 0.62 and slope of best fit of 0.81. Therefore when considering the wind generation scenarios production will be slightly overestimated, with good correlation with actual energy production; however the power output of an individual wind farm will not show great accuracy.

The ramp rates are defined by the change in power output between two points in time. For the wind power time series, the ramp rate is determined for each instance along the time series, and statistics are applied to understand the nature of the distribution of ramp rates. The standard deviation for the simulated and actual wind generation totals is shown in Table D.4 to assess the accuracy of the simulated data:

Table D.4: Comparison of the standard deviation of simulated and measured ramp rates of wind. The measured data was obtained from Transpower's SCADA data from 2013 to 2014 years.

Wind Farm	5 Minutes (MW)		30 Minutes (MW)		1 hour (MW)		2 hours (MW)	
	Act[1]	Sim[2]	Act	Sim	Act	Sim	Act	Sim
TUK	2.4	1.4	5.6	4.4	7.5	6.6	10.2	9.8
TAP	2.8	1.9	7.3	6.3	10.2	9.7	14.1	15.0
TRH	1.5	1.1	3.5	3.6	4.6	5.5	6.4	8.3
TWF	2.3	1.3	6.2	4.7	8.8	7.3	12.1	11.3
TWC	3.1	2.0	7.8	6.5	10.9	10.1	15.0	15.7
WWD	3.8	2.8	9.5	8.9	13.7	13.6	19.6	20.7
WHL	2.1	1.2	5.8	4.1	8.1	6.3	11.0	9.5
MAH	1.9	0.9	4.6	2.7	6.1	3.9	7.8	5.7
NZ	8.1	5.4	23.9	21.1	35.3	35.9	51.2	61.7

1. Actual Measured Ramp Rates. 2. Simulated Ramp Rates.

The simulation process underestimates the ramp rates at 5 minutes, which is possible due to the limited temporal resolution of the simulated data. The simulated data shows a high level of accuracy when considering ramp rates of the 30 minute to 1 hour time range, and overestimates by about 20 % for the 2 hour duration. Therefore when considering wind generation scenarios expect that the ramp rates will be accurate for 30 minute to 1 hour time frames, the results for 5 minute and 2 hours are still valuable, but account for errors at these time ranges. The probability density function of ramp rates is shown in Figure D.1 for New Zealand, which corroborate with the standard deviation values of Table D.4.

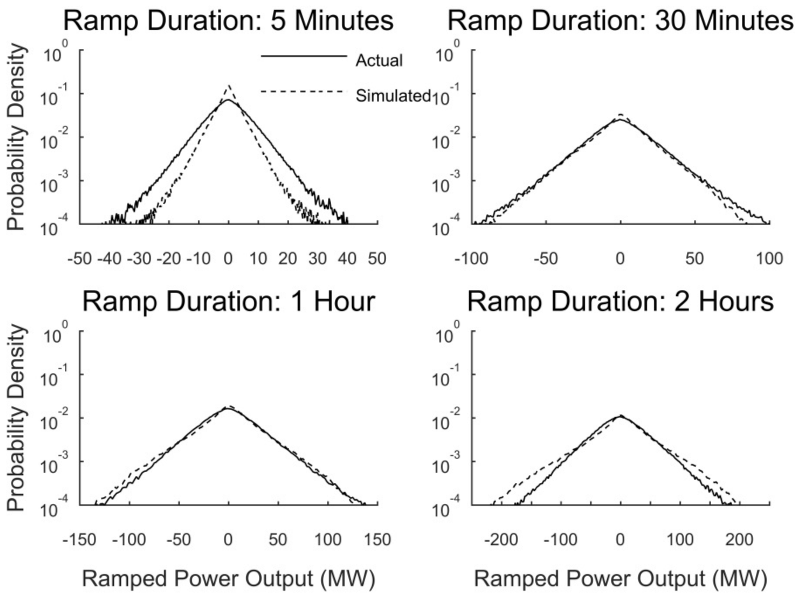

Figure D.1: Probability Density Function of measured (Actual) and simulated New Zealand ramp rates.

E. Results from the Dispatch

This appendix presents results from the dispatch that are important for determining the requirement of reserves in the future, and the availability of reserves, but firstly the energy balance results are given to assess the performance of the dispatch. The performance of the dispatch is not assessed by a metric, as this research does not have another model to assess the results against, but is rather considered by a sense of coherency. The results firstly consider the energy balance between new wind generation and historic thermal generation, and the impact this has on hydro reservoir levels. Secondly, the operation of the largest thermal units and the shift in HVDC flows are determined to calculate the largest risks on the grid.

E.1. Energy Balance

The energy balance, where old thermal generation is replaced by new wind generation, still shows a need for thermal generation, even as available wind generation exceeds the required amount. The reason for most of the required thermal generation is for periods of low hydro storage and low inflows, and capacity requirements to meet high demand during periods of low wind output.

The results of the thermal dispatch are shown in Figures E.1, E.2, E.3, and E.4, for scenarios of 1000, 2000, 3000, and 4000 MW of new wind generation capacity. At 1000 MW most of the wind generation simply replaces thermal generation, except for some periods of oversupply during low demand periods. By 2000 MW there are several blocks where there is an oversupply of wind energy and wind generation is curtailed, but there is not enough capacity during low wind periods so thermal generation is still required. This is especially seen in blocks 13 and 14 of Figure E.2. For 3000 MW most of the blocks see an oversupply of wind generation, and the greater consistency in capacity that it provides also means there is a reduction in the amount thermal generation required to meet capacity constraints. However, there are still blocks, 2, 3, 4, and 7, where there is insufficient wind generation. This is also for the 4000 MW scenario, blocks 2 and 3 with insufficient wind generation, because it is a period of low hydrological inflows but also as low wind generation.

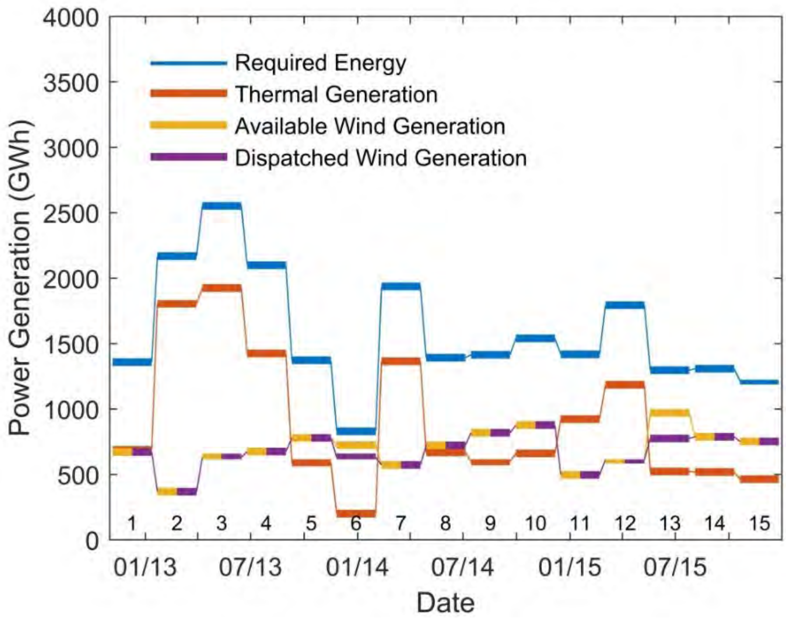

Figure E.1: Energy balance of thermal and wind generation for the 1000 MW scenario. The period of analysis is from 2013 to 2015. The required energy (blue) is to be meet by thermal generation (red) and dispatched wind generation (purple). Ideally the required energy would be meet by as much available wind generation as possible (yellow). The energy balance is solved for each 11 week block, which roughly gives five blocks per year.

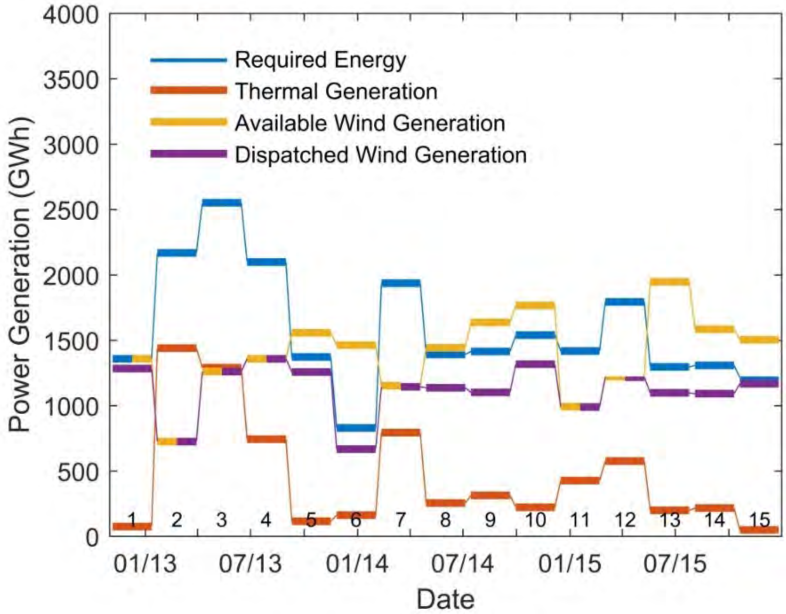

Figure E.2: Energy balance, 2000 MW Scenario.

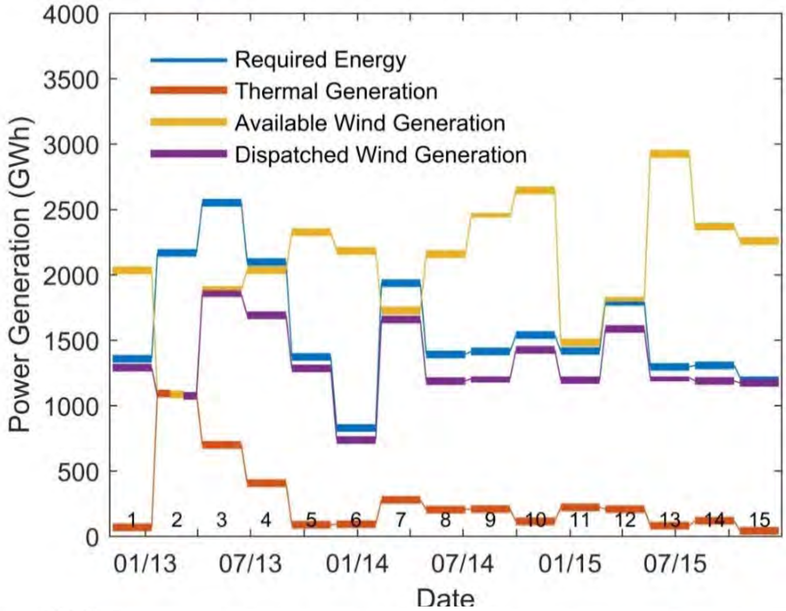

Figure E.3: Energy balance, 3000 MW Scenario.

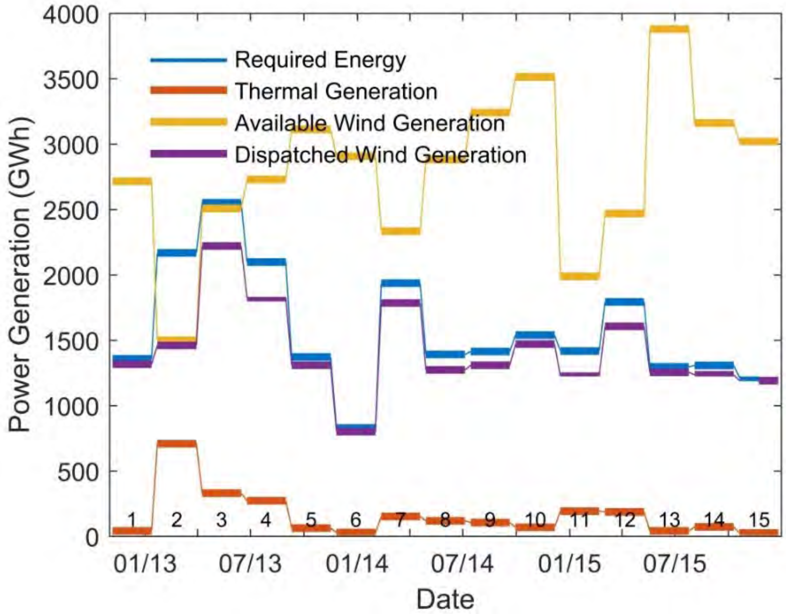

Figure E.4: Energy balance, 4000 MW Scenario.

In Figures E.5 and E.6, the balance of energy between thermal and wind generation is shown by scenario. It is apparent that as more wind capacity is added, the marginal value of the capacity decreases, as the dispatched wind generation asymptotically approaches the required energy. There are also some yearly differences of interest: 2013 has a greater demand for energy than 2014, while having a smaller amount of available wind generation, which has seen an earlier curtailment of wind generation in 2014.

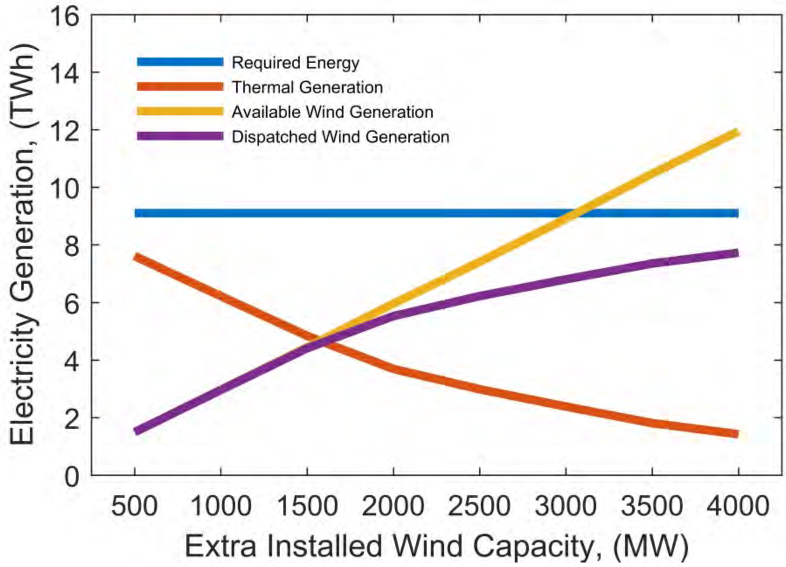

Figure E.5: Energy balance, year 2013.

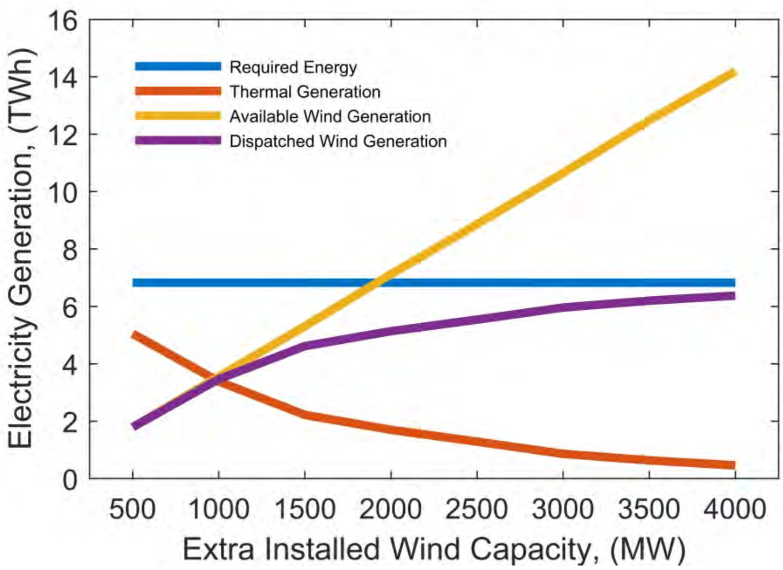

Figure E.6: Energy balance, year 2014.

Dispatching wind generation and thermal generation in 11-week blocks ensures that hydro reservoirs retain a similar storage profile, as the simulated hydro level returns to its historical level every 11 weeks. The resultant hydro reservoir levels are shown in Figure E.7 for the 2000 MW and 4000 MW case. There is limited deviation from the historical profile, and for some periods the 4000 MW case is closer to the historic profile than the 2000 MW case. This is due to periods where there is greater control of when wind generation can be curtailed.

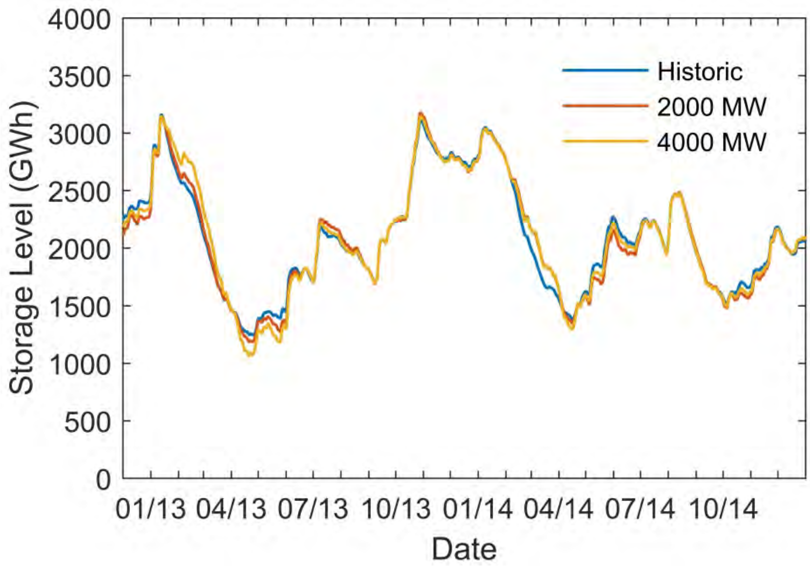

Figure E.7: The energy stored in the six most important storage lakes for two of the wind scenarios. The storage lakes are Taupo, Waikaremoana, Pukaki, Hawea, Manapouri, and Te Anau.

The performance of the dispatch model is not optimal, as there is greater ability to adjust hydro storage levels while reducing how much wind generation is curtailed. However, considering that the wholesale market does not have hindsight, the dispatch model is adequate. Further analysis on the effect of wind generation on energy usage and dry year security is being analysed by the GREEN Grid Project, which will provide greater accuracy in energy use.

E.2. Contingency Risk Size

In procuring enough Instantaneous Reserve to manage contingencies, the largest risks are usually set by a 400 MW CCGT, or by high HVDC transfer. With increasing penetrations of wind generation it is expected that the size of these risks will change, whether it is by decreased use of CCGT or a higher HVDC transfer north during periods of low wind generation. This section presents results of modelling.

With increasing penetrations of wind capacity, required thermal capacity decreases as seen in Table E.1, to better understand how much thermal capacity is required, duration curves are shown in Figure E.8. These duration curves imply that even for the 4000 MW case there is still significant requirement for thermal capacity in the range of 1000 MW. The result is that there is a decrease in contingency risk from thermal generation, as seen in Figure E.9 for 2014 and Figure E.10 for 2015. However, peak risk remains the same, assuming that a 400 MW CCGT remains in the generation mix. Although the risk thermal generation is zero for roughly 80% of the time at 4000 MW of installed wind generation.

Table E.1: The number of days each thermal generator was operated from November 2012 to December 2015, a total of 1155 days within the simulation. Note, Huntly mainly operated in November 2012, with one day in December 2012; Southdown and Otahuhu CCGT have since shutdown.

Wind Scenario	Current	500	1000	1500	2000	2500	3000	3500	4000
Huntly Unit 3	14	0	0	0	0	0	0	0	0
Southdown CC	811	1	0	0	0	0	0	0	0
Southdown GE	405	2	1	0	0	0	0	0	0
Otahuhu CCGT	741	277	90	50	25	14	10	5	4
Huntly Unit 1	352	253	169	104	76	58	32	13	8
Huntly Unit 2	477	388	198	81	48	29	18	12	6
Huntly Unit 4	607	516	272	149	98	69	39	21	14
McKee	821	754	483	320	169	134	87	78	25
Taranaki CCGT	357	345	269	192	148	98	72	49	33
Huntly Unit 6	263	254	177	114	93	58	45	36	28
Stratford 21	860	802	598	394	277	203	143	116	100
Stratford 22	843	762	574	356	272	212	144	109	98
Kapuni	1148	1049	793	552	375	284	200	147	127
Huntly Unit 5	1079	1055	930	707	533	424	337	278	230

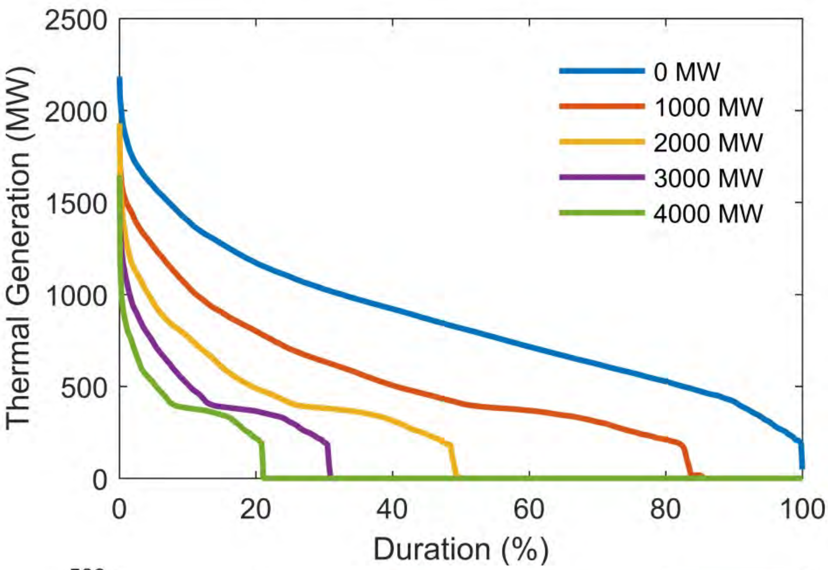

Figure E.8: Generation duration curves for the total thermal generation. Shown for the historical case (0 MW), and for four of the wind generation scenarios. The data is derived from the dispatch model, over a period of three years from December 2012 to November 2015.

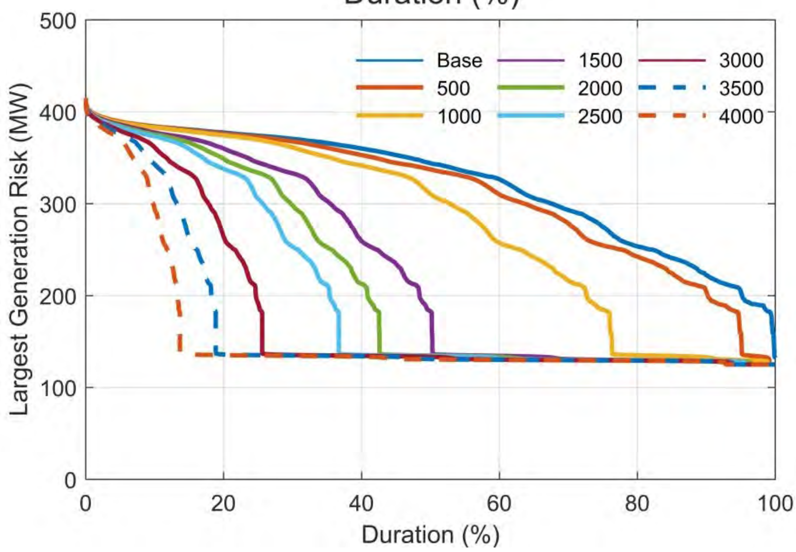

Figure E.9: The highest generator risk for New Zealand in 2014.

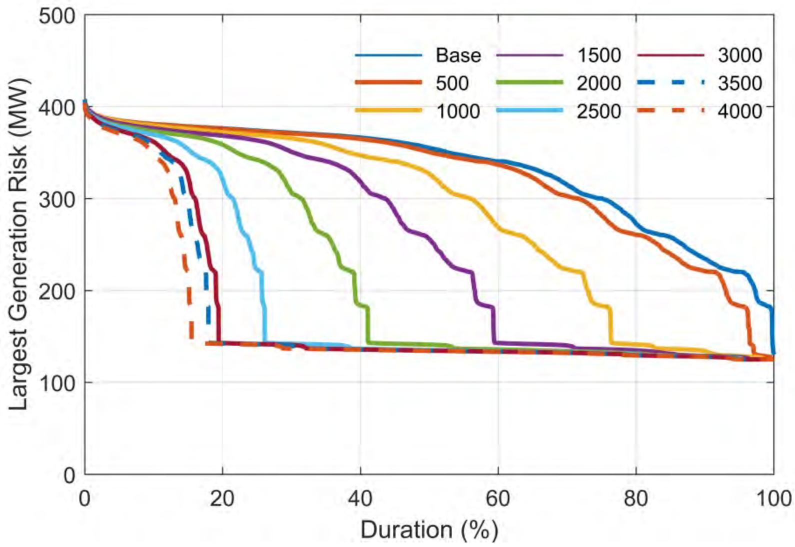

Figure E.10: The highest generator risk for New Zealand in 2015.

The modeling of τ_m for 2014 and 2015, are in Figures G.11 to G.14.

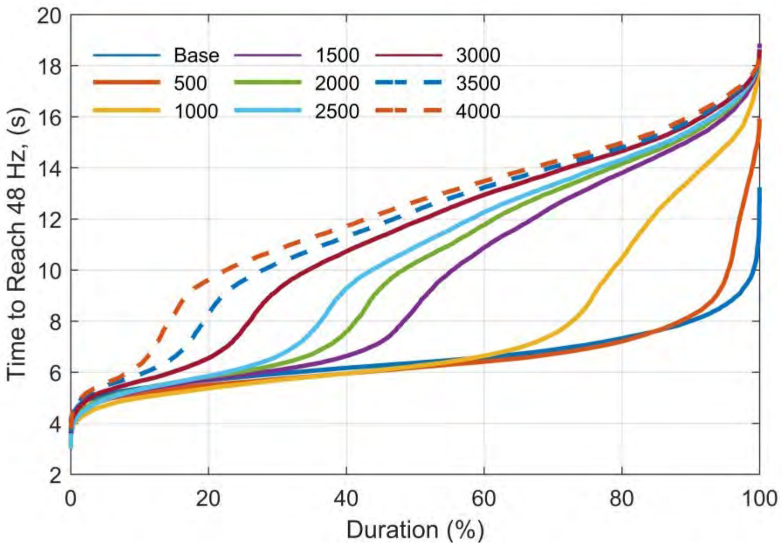

Figure E.11: The unaided time to reach 48 Hz for the largest generator CE in 2014.

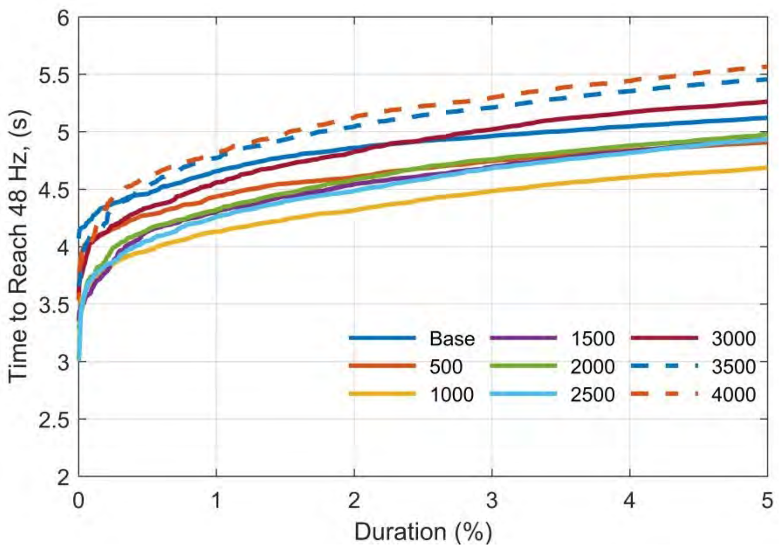

Figure E.12: Detailed view of Figure E.11.

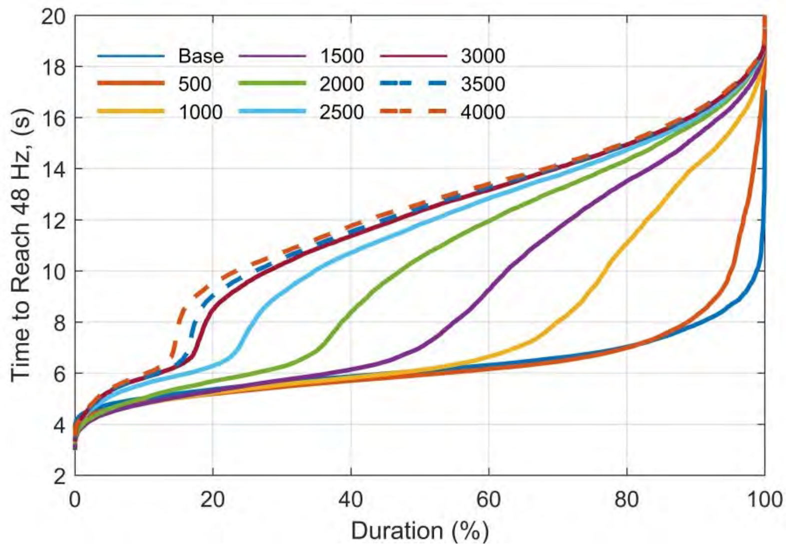

Figure E.13: The unaided time to reach 48 Hz for the largest generator CE in 2015.

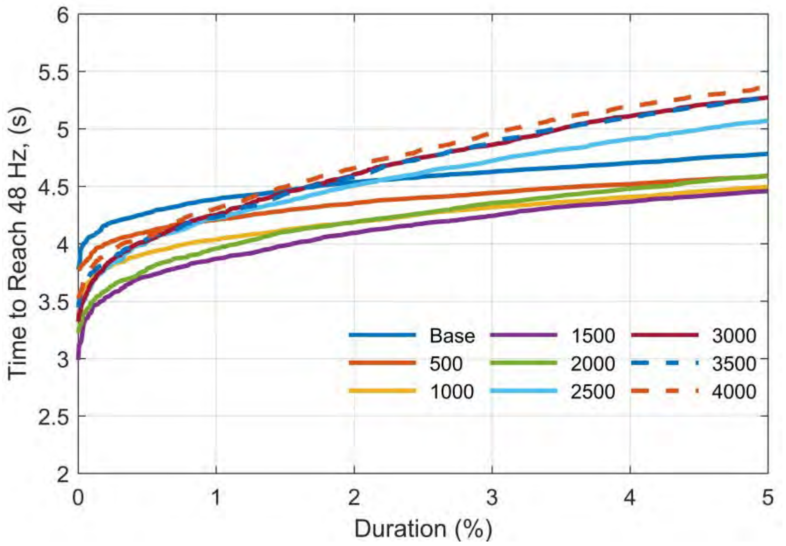

Figure E.14: Detailed view of Figure E.13.

The HVDC link is a source of risk for both islands, and with the increased presence of variable renewable energy, HVDC transfers are expected to increase. High north transfers are expected to occur during periods of low North Island wind generation and high South Island generation. Consequently, the reserve demand for these periods is expected to increase and put added strain on security. The dispatch model is used to predict changes in HVDC transfer.

The dispatched model does not force the HVDC capacity constraint in solving the dispatch, and it does not limit transfer as a result of reserve constraints. Therefore, the HVDC link is free to provide the optimal transfer of energy between the two islands. There are periods when wind generation is curtailed, allowing for choice of where it is curtailed, and so HVDC transfer can be reduced. This has been applied to the model while trying to reduce transfer below 1200 MW but it is not always successful, and results in greater curtailment of South Island wind generation. The results from dispatch model are seen in duration curves, Figure E.15 and G.16. The results show a significant increase in HVDC transfer, even for a further 1000 MW of wind generation, where transfer is greater than 1000 MW for roughly 4% of the time.

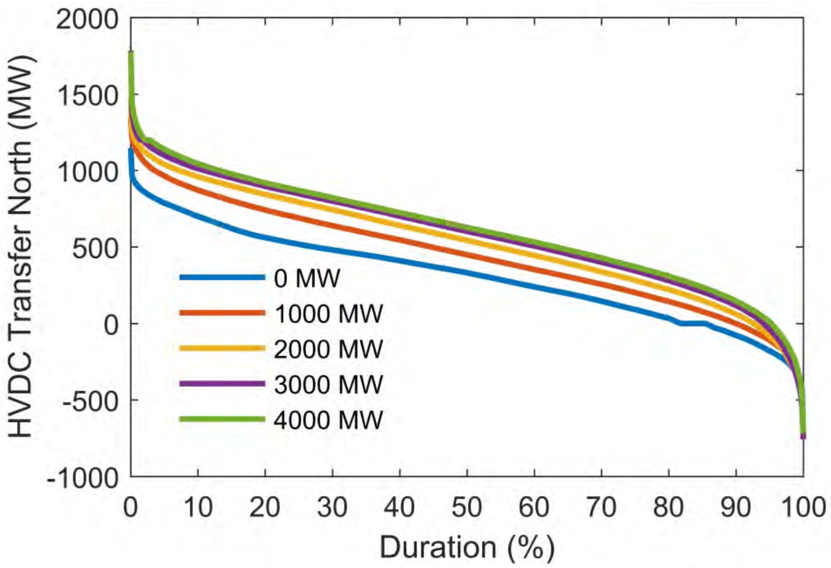

Figure E.15: Duration curve of HVDC transfer, for the three years from December 2012 to November 2015.

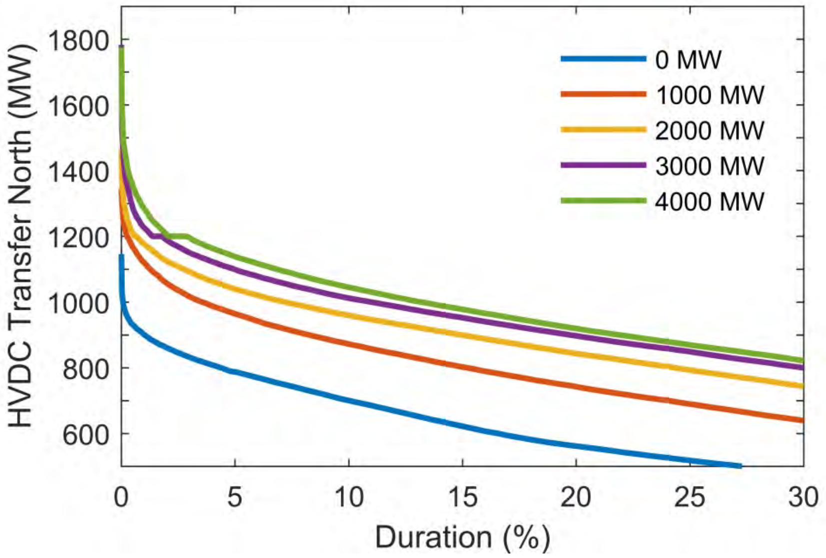

Figure E.16: Zoomed in view of Figure E. 15.

F. Simulation of Grid Inertia

This appendix presents the full results of modelling the changes in inertia for each wind scenario. The results are presented as duration curves, and then 1% percentile values are shown in a table. The results show the difference between inertia from entirely generation plant, and then inertia from generation plant and the inertia attributable to load.

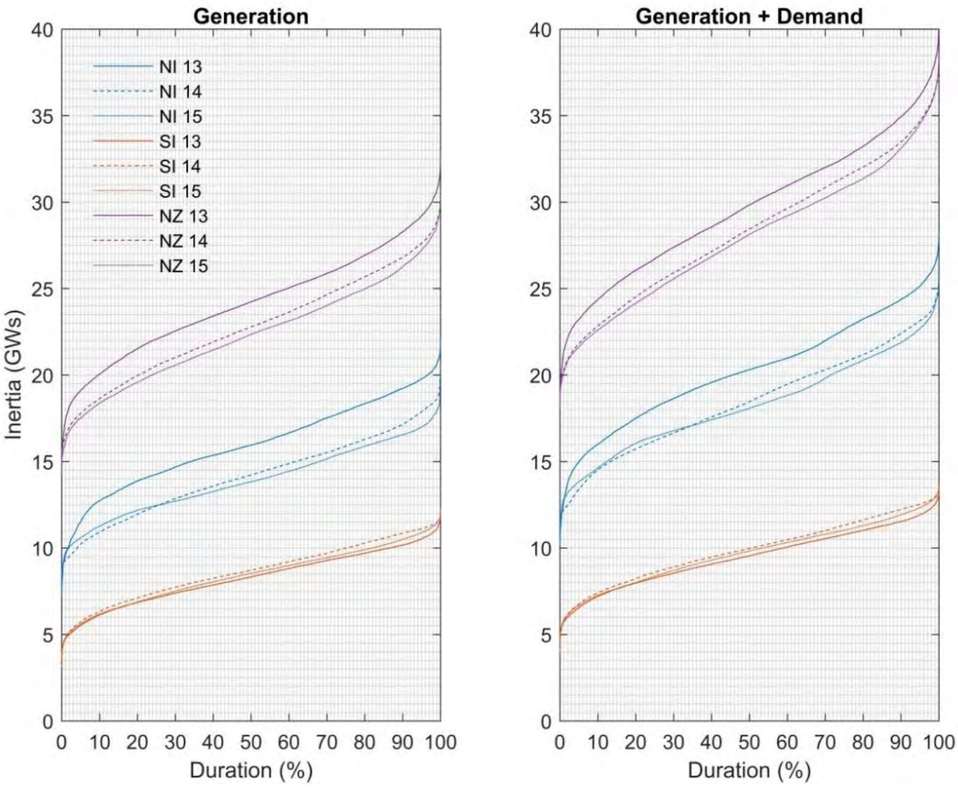

Figure F.1: Duration of inertia throughout a year for the historic generation scenario. The data is shown for the North Island (NI), South Island (SI), and the whole of New Zealand (NZ); and also for the years 2013, 2014, and 2015.

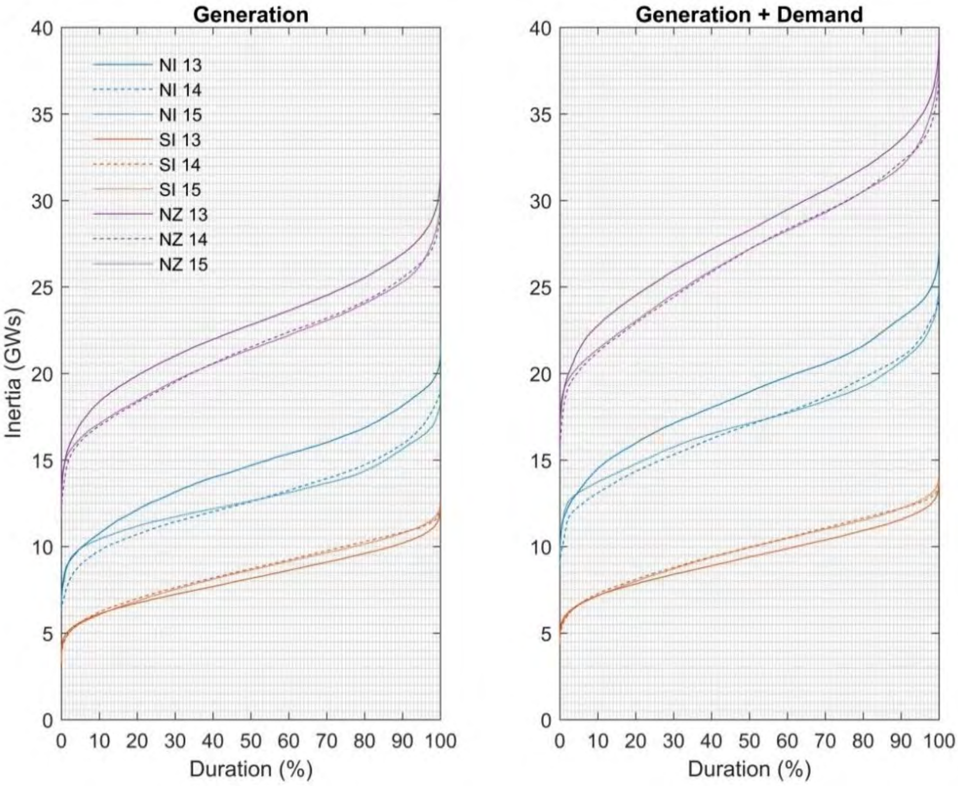

Figure F.2: 500 MW scenario.

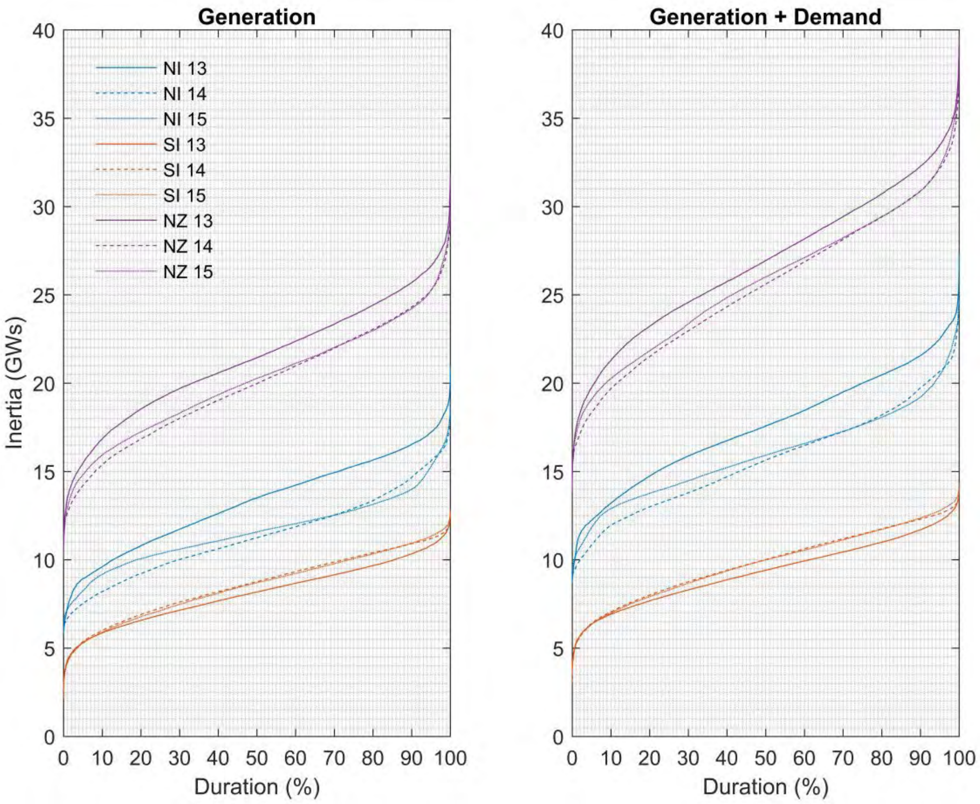

Figure F.3: 1000 MW scenario.

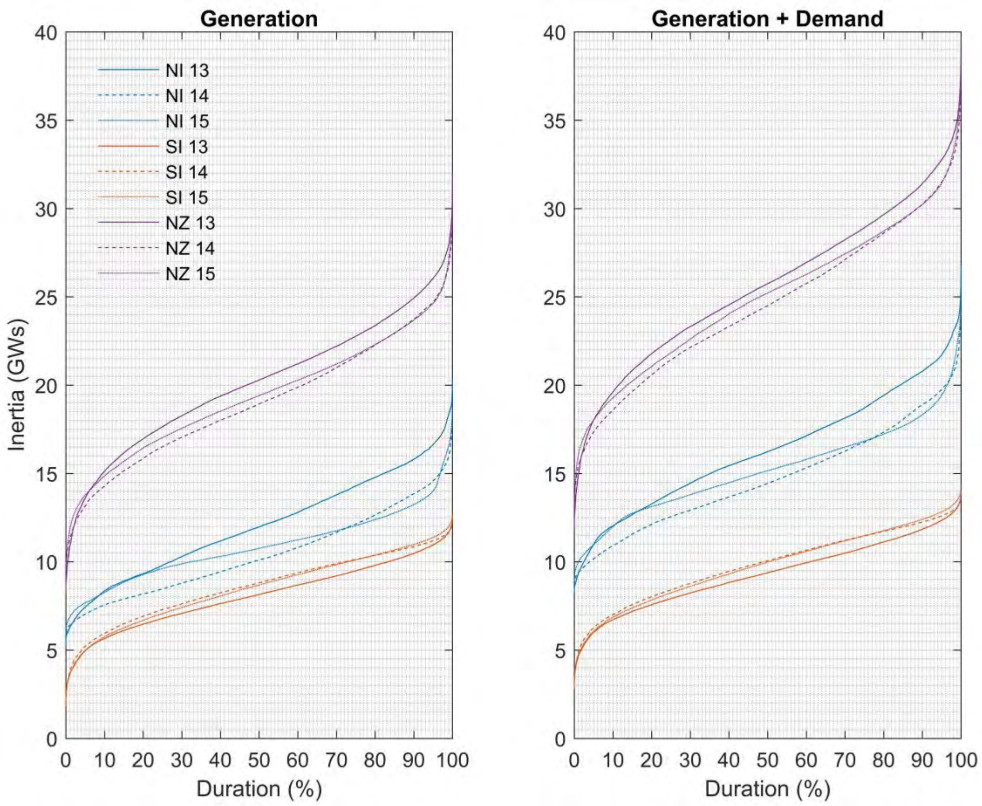

Figure F.4: 1500 MW scenario.

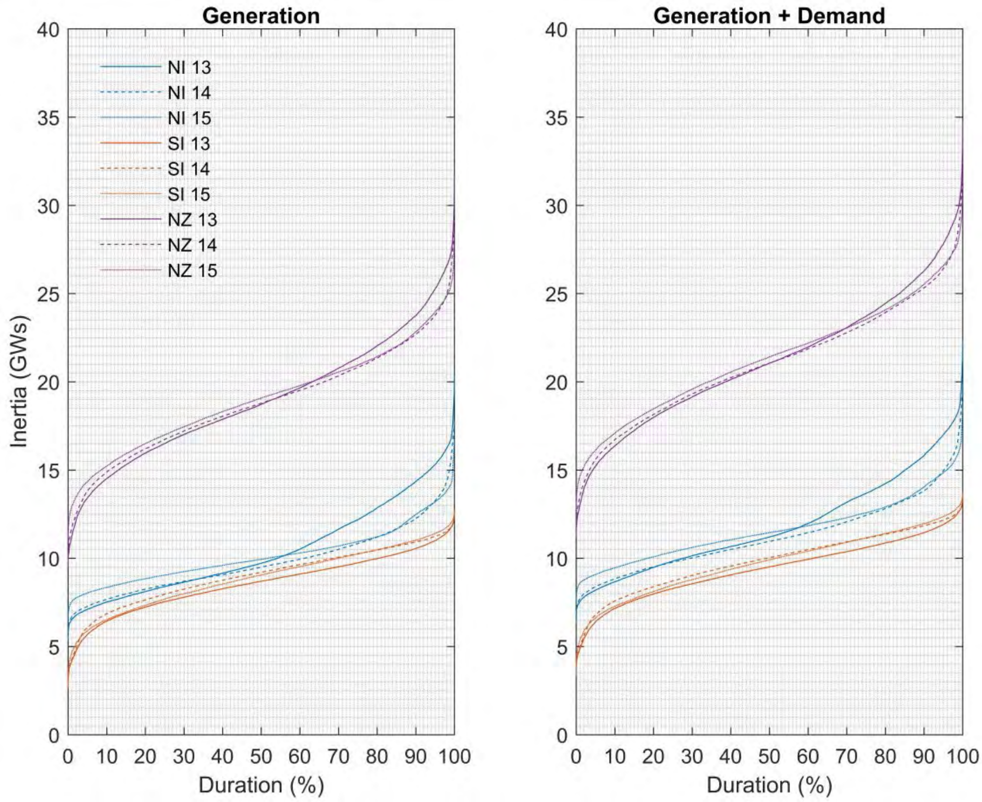

Figure F.5: 2000 MW scenario.

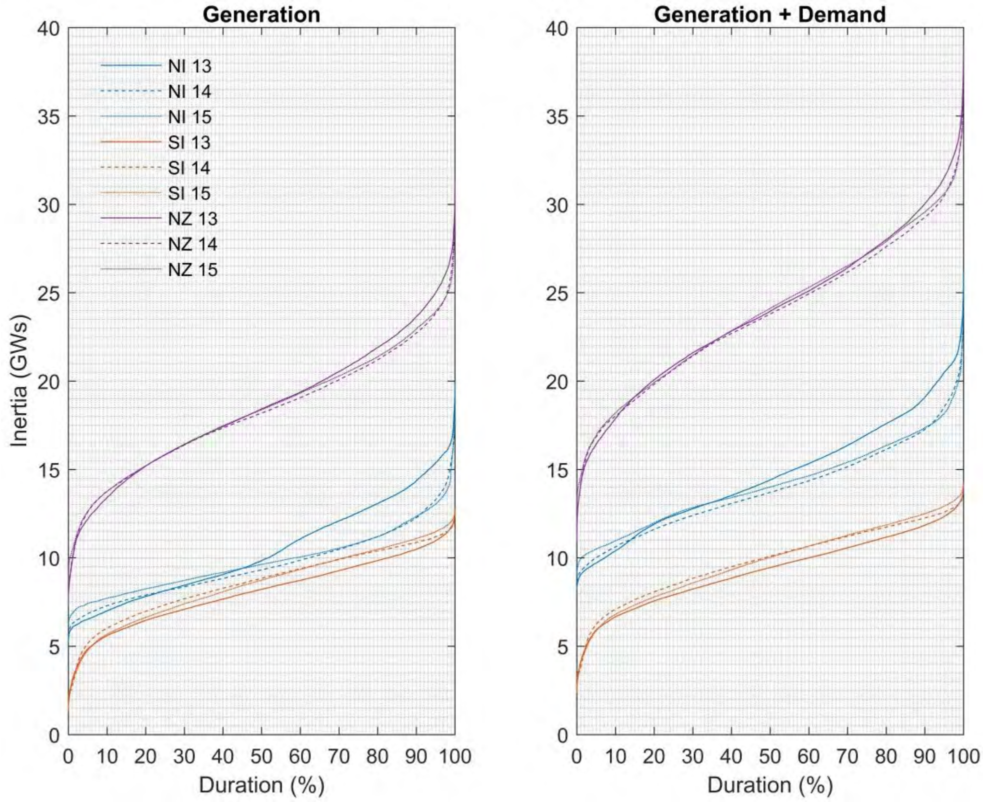

Figure F.6: 2500 MW scenario.

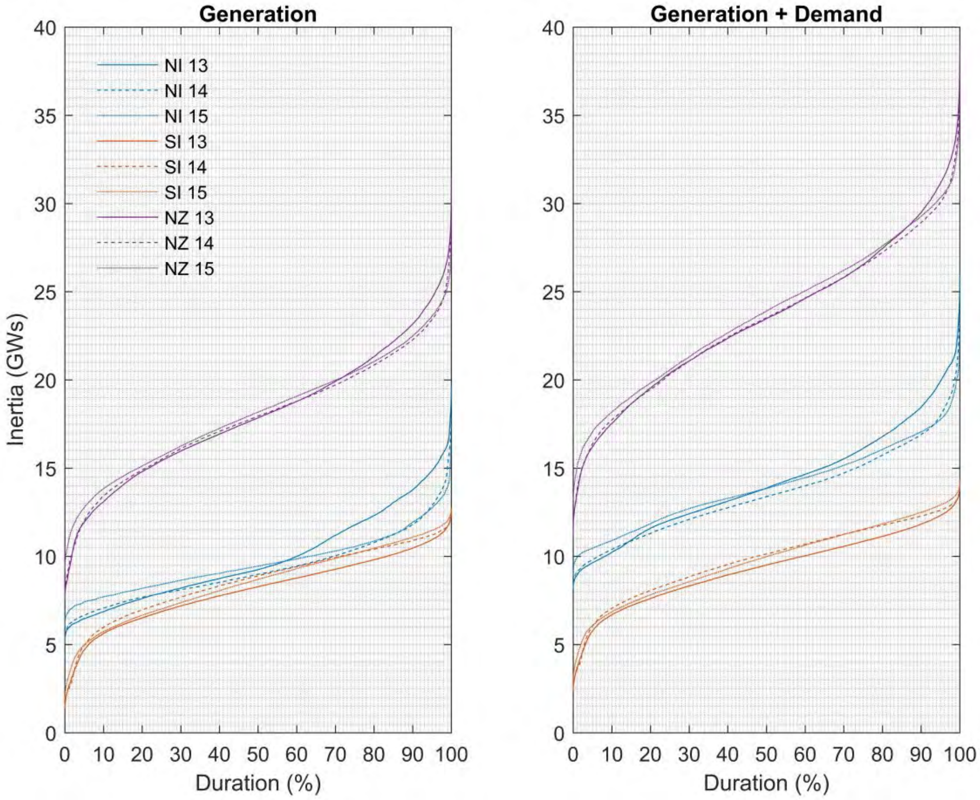

Figure F.7: 3000 MW scenario.

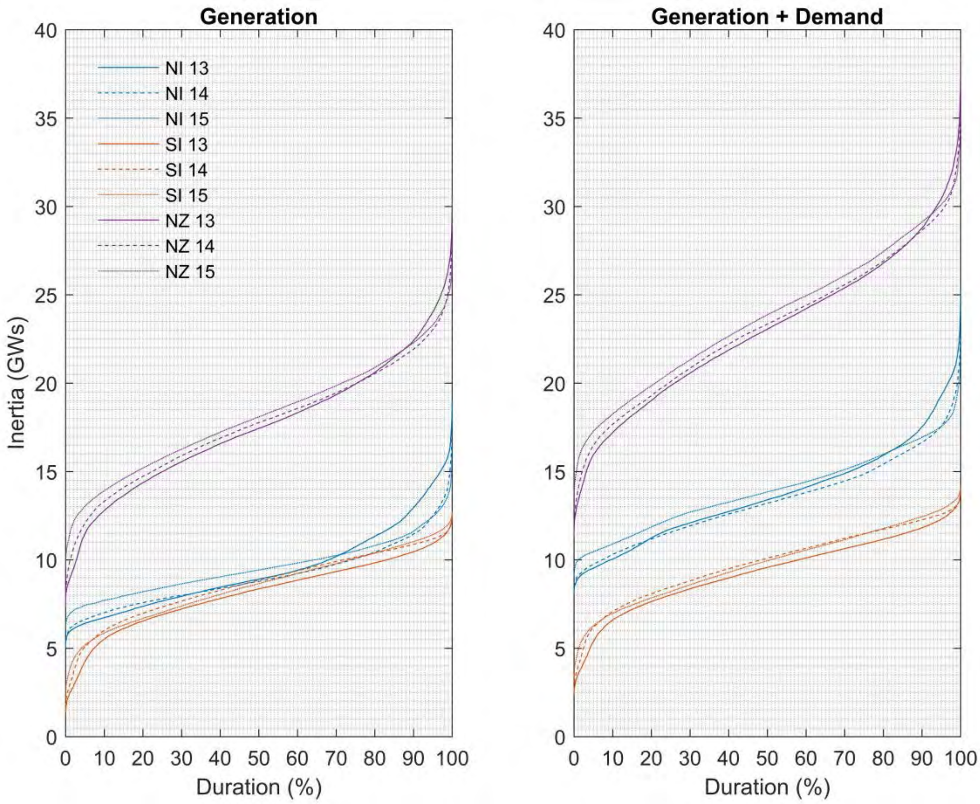

Figure F.8: 3500 MW scenario.

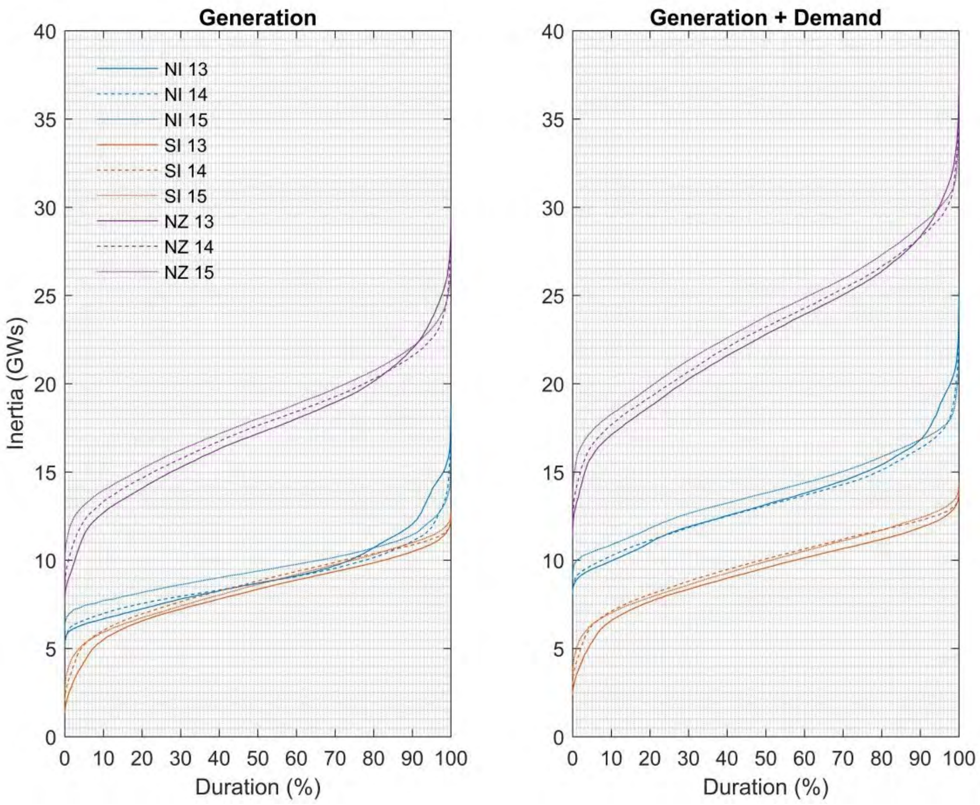

Figure F.9: 4000 MW scenario.

Table F.1: 1 Percentile inertia for the North Island.

Scenario	Generation			Generation and Demand		
	2013	2014	2015	2013	2014	2015
Current	9,540	9,300	9,738	12,640	12,179	12,826
500	8,600	7,290	8,390	11,650	10,360	11,830
1000	7,280	6,670	7,190	10,540	9,600	10,310
1500	6,290	6,400	6,850	9,300	9,360	9,970
2000	6,130	6,380	6,860	9,100	9,350	9,930
2500	6,040	6,250	6,860	9,050	9,220	9,950
3000	5,940	6,140	6,880	8,930	9,120	9,930
3500	5,930	6,110	6,910	8,930	9,110	9,980
4000	5,930	6,080	6,920	8,880	9,130	9,960

Table F.2: 1 Percentile inertia for the South Island

Scenario	Generation			Generation and Demand		
	2013	2014	2015	2013	2014	2015
Current	4,740	4,790	4,790	5,700	5,730	5,830
500	4,890	4,630	4,680	5,870	5,630	5,710
1000	4,320	4,200	4,160	5,320	5,200	5,240
1500	3,620	3,780	3,630	4,610	4,810	4,690
2000	3,310	3,380	3,210	4,350	4,410	4,290
2500	3,080	2,760	2,920	4,110	3,790	3,990
3000	2,600	2,510	3,230	3,680	3,560	4,270
3500	2,420	2,860	3,770	3,500	3,920	4,830
4000	2,430	3,220	3,950	3,500	4,250	5,010

Table F.3: 1 Percentile inertia for New Zealand

Scenario	Generation			Generation and Demand		
	2013	2014	2015	2013	2014	2015
Current	17,350	16,500	16,100	21,350	20,260	20,190
500	15,050	14,120	14,950	18,960	18,070	19,040
1000	13,510	12,660	12,960	17,480	16,570	17,090
1500	10,850	12,280	11,810	14,850	15,360	15,960
2000	10,200	10,980	10,830	14,270	15,140	14,990
2500	9,770	9,960	10,430	14,100	14,100	14,590
3000	9,160	9,370	10,890	13,560	13,760	15,050
3500	8,870	9,830	11,350	13,260	13,940	15,500
4000	8,950	10,050	11,630	13,250	14,180	15,700

G. Inertia Estimation from Events

In Section 4.1, the process of estimating inertia from individual generating units is described. However, that process did not incorporate all forms of inertia, as they were difficult to calculate. This appendix validates the inertia values from that section by considering several contingent events and the resultant Rate of Change of Frequency (RoCoF). The results indicate that inertia should be increased for these unknown sources, so that for every MW of demand in the North Island, inertia should increase by 1.5 MWs and for the South Island 0.75 MWs, Table G.1 and G.2 respectively.

Table G.1: Validation of North Island Inertia.

Date	Time	Location	Pre-Contingency Frequency (Hz)	Extrema Frequency (Hz)	Time to reach Extrema (s)	RoCoF (Hzs^{-1})	ΔP (MW)	Event Inertia (MWs)	Calculated Inertia (MWs)	Inertia Difference (MWs)	Demand (MW)	Ratio (MWs/MW)
9/05/2013	11:03	Stratford	49.962	49.260	5.1	-0.260	-236	22692	15630	7062	3350	2.11
20/05/2013	10:58	HVDC	49.883	48.612	6.3	-0.474	-481	25369	19620	5749	3250	1.77
22/05/2013	10:03	HVDC	49.927	49.319	7.9	-0.157	-142	22611	19260	3351	3390	0.99
20/06/2013	19:13	HVDC	50.060	49.138	5.3	-0.273	-313	28663	20560	8103	4140	1.96
17/10/2013	02:15	HVDC	50.026	50.607	5.7	0.158	112	17722	13530	4192	2100	2.00
22/02/2014	19:39	Huntly	50.046	49.146	2.6	-0.507	-363	17899	11420	6479	2840	2.28
24/03/2014	12:24	Huntly	50.034	49.391	7.0	-0.149	-134	22483	17220	5263	3130	1.68
10/04/2014	19:35	Otahuhu	50.069	49.249	6.2	-0.195	-194	24872	16850	8022	3390	2.37
25/11/2014	22:08	Stratford	49.992	49.382	5.9	-0.213	-142	16667	10670	5997	2750	2.18

Table G.2: Validation of South Island Inertia.

Date	Time	Location	Pre-Contingency Frequency (Hz)	Extrema Frequency (Hz)	Time to reach Extrema (s)	RoCoF (Hzs^{-1})	ΔP (MW)	Event Inertia (MWs)	Calculated Inertia (MWs)	Inertia Difference (MWs)	Demand (MW)	Ratio (MWs/MW)
14/01/2013	13:02	Tiwai	49.991	50.704	4.0	0.314	188	14968	10610	4358	1820	2.39
4/04/2013	19:37	HVDC	50.001	48.434	4.4	-0.462	-218	11797	6560	5237	1780	2.94
10/04/2013	04:12	Tiwai	50.006	49.408	7.0	-0.159	-68	10692	5010	5682	1200	4.73
16/04/2013	21:01	HVDC	49.961	49.210	3.2	-0.307	-123	10016	6760	3256	1710	1.90
20/05/2013	10:58	HVDC	50.017	53.215	4.1	1.123	508	11309	9840	1469	1750	0.84
22/05/2013	10:03	HVDC	50.038	50.951	5.0	0.274	145	13230	8630	4600	1830	2.51
13/06/2013	02:35	HVDC	49.966	50.722	5.4	0.168	70	10417	7080	3337	1360	2.45
20/06/2013	19:12	HVDC	50.055	52.062	4.2	0.696	323	11602	10160	1442	2050	0.70
30/06/2013	17:43	HVDC	50.019	50.951	5.1	0.268	119	11101	9320	1781	1970	0.90
24/09/2013	15:35	HVDC	50.012	50.677	5.4	0.177	74	10452	8630	1822	1700	1.07
17/10/2013	02:15	HVDC	49.951	49.153	3.2	-0.300	-109	9083	6160	2923	1290	2.27
18/10/2013	12:50	HVDC	49.968	50.519	7.2	0.176	70	9943	7070	2873	1620	1.77
29/10/2013	10:06	HVDC	50.028	49.100	5.1	-0.220	-106	12045	10070	1975	1800	1.09
24/11/2013	04:53	HVDC	50.015	52.810	4.2	0.977	376	9621	7720	1901	1400	1.35
10/12/2013	00:40	HVDC	50.002	50.700	5.9	0.177	81	11441	7290	4151	1530	2.71
15/11/2014	05:51	HVDC	50.063	48.810	4.9	-0.320	-93	7266	6200	1066	1410	0.76
27/11/2014	13:32	Manapouri	50.014	48.608	4.7	-0.954	-370	9696	8490	1206	1830	0.66
3/03/2015	13:31	HVDC	49.978	51.011	5.8	0.281	140	12456	10260	2196	1820	1.21

H. List of Dates for Ramp Events

Table H.1: List of dates for positive ramping events corresponding to Table 5.5.

Event ID	Date and Time	Event ID	Date and Time
1	20/04/2013 7:00	12	9/02/2015 22:00
2	27/11/2012 11:00	13	14/05/2013 14:00
3	22/09/2014 7:00	14	12/11/2013 11:00
4	26/06/2014 20:00	15	27/04/2015 13:00
5	17/08/2013 3:00	16	30/04/2015 5:00
6	15/03/2013 8:00	17	12/08/2014 8:00
7	20/06/2013 5:00	18	12/11/2014 16:00
8	26/05/2014 15:00	19	13/04/2015 16:00
9	17/11/2012 23:00	20	28/09/2013 11:00
10	15/01/2013 10:00	21	4/02/2013 22:00
11	30/12/2013 17:00	22	17/01/2014 18:00

Table H.2: List of dates for negative ramping events corresponding to Table 5.6.

Event ID	Date and Time	Event ID	Date and Time
1	20/04/2013 7:00	14	3/01/2014 22:00
2	27/11/2012 20:00	15	28/11/2014 18:00
3	18/07/2013 3:00	16	9/07/2013 14:00
4	3/10/2013 1:00	17	22/09/2014 10:00
5	1/12/2013 8:00	18	25/03/2014 21:00
6	21/11/2013 14:00	19	28/11/2012 20:00
7	1/12/2013 9:00	20	17/01/2013 18:00
8	3/03/2014 3:00	21	20/06/2013 9:00
9	8/09/2013 1:00	22	12/11/2013 9:00
10	6/08/2014 3:00	23	2/08/2014 18:00
11	15/03/2013 8:00	24	5/01/2014 1:00
12	13/04/2015 16:00	25	5/03/2014 23:00
13	14/08/2014 18:00	26	17/01/2014 18:00

I. Fast Instantaneous Reserve Offers

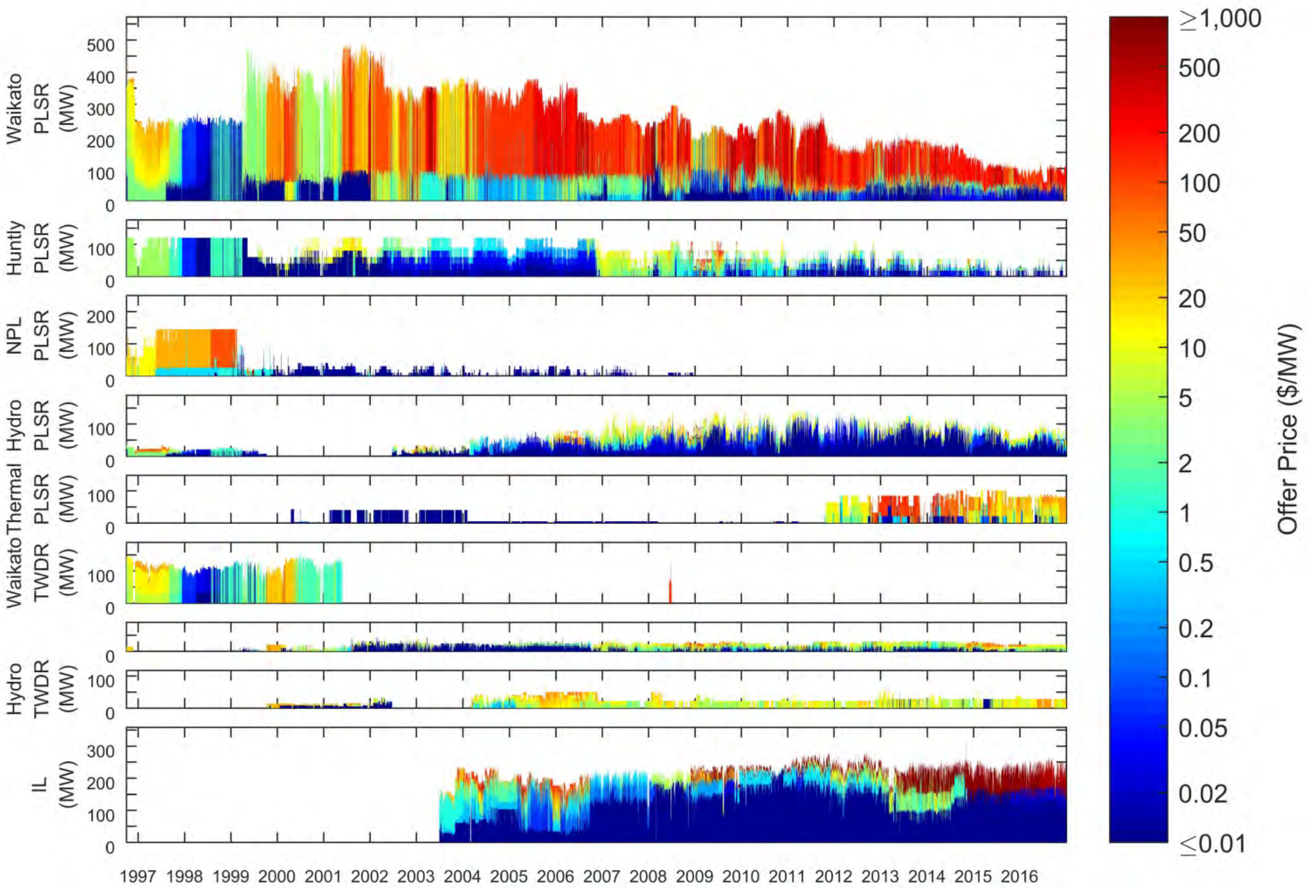

Figure I.H.1: North Island Fast Instantaneous Reserve Offers. Each plot is produced by finding the highest offered reserve out of each day since the Electricity Market has been in operation, except for Interruptible Load which only has data since July 2003. Offers are grouped by blocks: NPL is New Plymouth power station; Hydro PLSR includes the Waikaremoana Scheme, Matahina, Mangahao, Patea, Tongariro Scheme, and the Wheao Scheme; Thermal PLSR includes the Te Awamutu gas turbine, Otahuhu CCGT, Poihipi Rd geothermal plant, and Stratford. Hydro TWDR includes the Waikaremoana Scheme, Matahina, and Patea. The seventh plot is the Tongiriro Scheme TWDR.

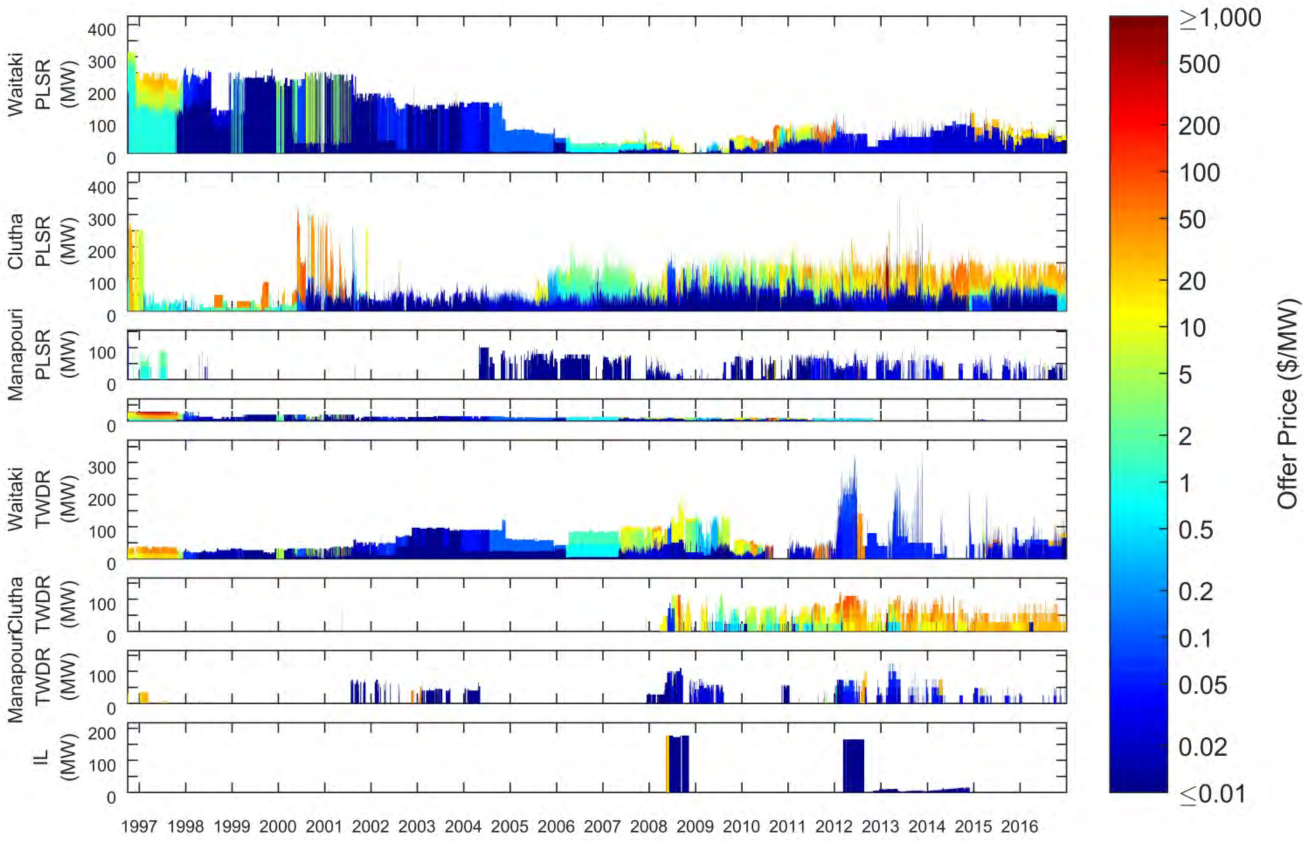

Figure I.2: South Island Fast Instantaneous Reserve Offers. Each plot is produced by finding the highest offered reserve out of each day since the Electricity Market has been in operation, except for Interruptible Load which only has data since July 2003. Offers are grouped by blocks: Waitaki does not include the two Tekapo stations; the fourth plot is for other South Island hydro generation, which includes Cobb, Coleridge, Highbank, and the two Tekapo power stations.

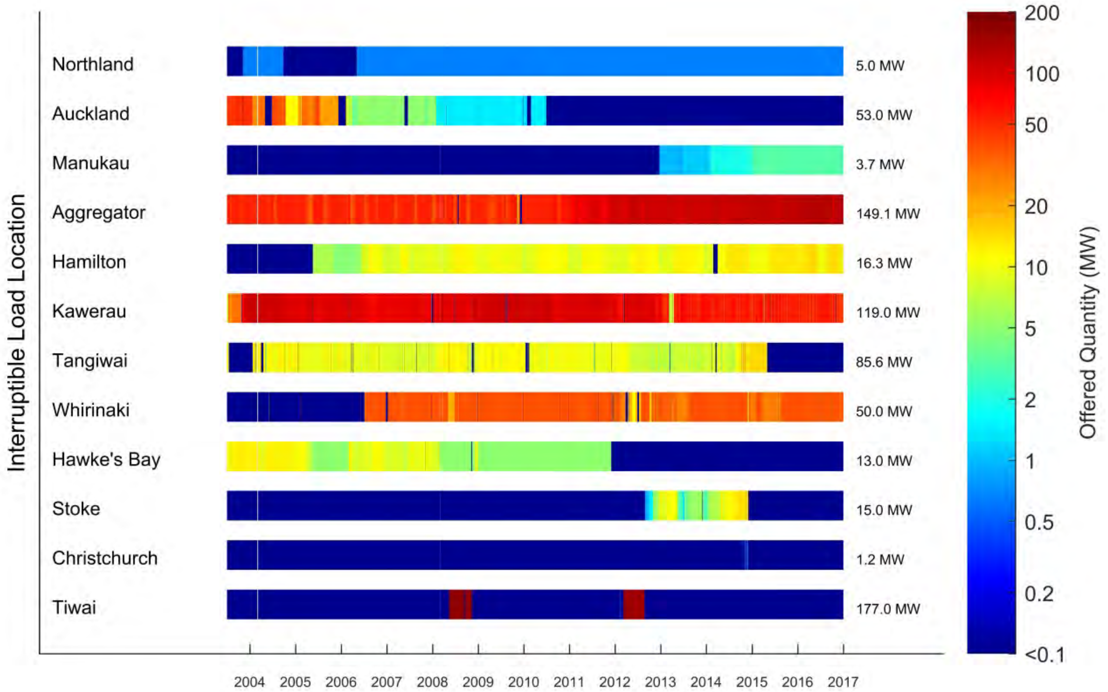

Figure I.3: Offered Fast Instantaneous Reserve from Interruptible Load providers. This plot was produced by taking the largest offer in each day and colouring the total offered quantity. This figure does not give any information about the price of the offered reserve. (Note: the blue colour generally implies the absence of an offer.) The numbers on the right side of the bar are absolute maximums. Aggregator also includes Glenbrook Steel Mill.

Table I.1: List of providers of PLSR and TWDR in the North Island since the inception of the wholesale electricity market.

Station	Type	Reserve	Max Offered Quantity (MW)	Start Date	End Date	Comment
Waikato	PLSR	FIR	532	1/10/1996	-	Consistent source of North Island reserves. Has not offered TWDR since April 2015, has not consistently offered TWDR since 31st May 2001, except for a brief period in June 2008. TWDR was only offered from Arapuni, Atiamuri, Maraetai, and Ohakuri.
		SIR	428		21/03/2015	
	TWDR	FIR	149		-	
		SIR	205		9/04/2015	
Huntly	PLSR	FIR	136	1/10/1996	-	Fairly consistent source of North Island reserve, but diminishing as more units are taken out of the market. Reserve is only offered from the Rankine units.
		SIR	140			
New Plymouth	PLSR	FIR	210	1/10/1996	15/12/2008	Sporadically offering reserve before leaving the market in 2008.
		SIR	160			
Waikaremoana	PLSR	FIR	39	1/10/1996	-	Fairly consistent source of North Island reserve. Swapped from PLSR to TWDR and back again from late 1999 to middle 2002.
		SIR	86			
	TWDR	FIR	35	15/09/1997	22/06/2002	
		SIR	68			
Matahina	PLSR	FIR	53	1/10/1996	-	Consistent source of North Island reserve from March 2004, prior to that very sporadic.
		SIR	51			
	TWDR	FIR	56	26/06/2003		
		SIR	73	1/01/2001		
Mangahao	PLSR	FIR	44	1/10/1996	8/12/2014	Initially only providing a very small amount of reserve at the start of the electricity market, only sporadically started providing reserve in March 2007.
		SIR	8			
Patea	PLSR	FIR	23	1/03/2004	-	Consistent source of North Island reserve. (Note: Patea's name plate capacity is 32 MW, therefore the TWDR FIR offer is likely to be constrained by the power station capacity).
		SIR	22			
	TWDR	FIR	55	10/03/2004		
		SIR	31			
Tongariro	PLSR	FIR	53	1/10/1996	-	Consistent source of North Island reserve. Had a preference for TWDR over PLSR from 1999 to 2006.
		SIR	100			
	TWDR	FIR	50			
		SIR	171			
Wheao	PLSR	FIR	8	5/02/2008	-	Small consistent source of North Island reserves from February 2008.
		SIR	16			
Te Awamutu	PLSR	FIR	20	31/12/1999	31/12/1999	Trialled providing reserve for one day just before the turn of the millennium.
		SIR	20			
Otahuhu CCGT	PLSR	FIR	40	18/04/2000	22/09/2015	Sporadically offered reserve before leaving the market in 2015.
		SIR	58			
Poihipi Rd	PLSR	FIR	5	18/04/2000	29/11/2000	Briefly provided a minor amount of reserve in 2000.
		SIR	20			
Stratford	PLSR	FIR	88	15/10/2011	-	CCGT has been providing SIR since 2005, has been providing FIR since 2011 with OCGT.
		SIR	175	9/06/2005		

Table I.2 List of providers of PLSR and TWDR in the South Island since the inception of the wholesale electricity market.

Station	Type	Reserve	Max Offered Quantity (MW)	Start Date	End Date	Comment
Waitaki	PLSR	FIR	386	1/10/1996	-	Consistent source of South Island reserve.
		SIR	366			
	TWDR	FIR	330			
		SIR	500			
Clutha	PLSR	FIR	392	1/10/1996	-	Consistent source of South Island reserve. Consistently offering TWDR from the 23rd March 2008.
		SIR	572			
	TWDR	FIR	126			
		SIR	309			
Manapouri	PLSR	FIR	114	1/10/1996	-	Sporadic source of reserve for the South Island, only significantly supplying reserve from middle 2004, and only TWDR during dry periods.
		SIR	162			
	TWDR	FIR	125			
		SIR	280			
Cobb	PLSR	FIR	3	1/10/1996	15/04/1998	Minor source of reserve, stopped offering FIR before leaving ECNZ, and stopped providing SIR after being a short time with Trustpower.
		SIR	8		3/06/2003	
Coleridge	PLSR	FIR	13	1/10/1996	15/04/1998	Minor source of reserve. Stopped offering reserve before leaving ECNZ.
		SIR				
Highbank	PLSR	FIR	0.2	1/10/1996	1/03/1999	Very small provider of reserves. Stopped offering before leaving ECNZ.
		SIR	0.2			
Tekapo	PLSR	FIR	20	1/10/1996	-	Consistent source of South Island reserves until December 2012.